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This study analyzes the horizontal market power of a dominant generation firm in a restructured electricity market. Electric restructuring is a form of deregulation where competition occurs in the generation of electricity. Horizontal market power is the ability of a firm to profitably set market price above marginal cost due to the firm's ownership of a large share of the available generation. This model shows that in Colorado the incumbent regulated monopoly, Public Service Company (PSCo), has the potential to set prices above marginal cost 93% of the year. The study then investigates three scenarios under which PSCo's market power might be mitigated. Relaxing transmission constraints within the Rocky Mountain Power Area has little effect on PSCo's market power. Entry by 1,000 MW of fringe generation reduces the amount of the year over which a markup could be applied to 72 %. If PSCo agrees to divest 50% of its generation, markups can be applied only 37% of the year. These results suggest that requiring the incumbent monopoly to divest a portion of its generation is the most effective option available to state policymakers implementing restructuring in a state with a dominant firm.

AN EMPIRICAL ANALYSIS OF A DOMINANT FIRM'S MARKET POWER IN A RESTRUCTURED ELECTRICITY MARKET, A CASE STUDY OF COLORADO

by

Al Sweetser

A thesis submitted to the Faculty and the Board of Trustees of the Colorado School of Mines in partial fulfillment of the requirements for the degree of Doctor of Philosophy (Mineral Economics).

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ABSTRACT

This study analyzes the horizontal market power of a dominant generation firm in a restructured electricity market. Electric restructuring is a form of deregulation where competition occurs in the generation of electricity. Horizontal market power is the ability of a firm to profitably set market price above marginal cost due to the firm's ownership of a large share of the available generation. In the U.S., there are 32 states where one firm owns at least 40% of the existing generation. As these states consider electric restructuring, analysis of the market power that a dominant firm can exercise could become increasingly important. This type of analysis has been largely ignored in published economic analyses of electric restructuring. Many of the factors that determine a firm's ability to exercise market power, such as the number and capacity of transmission paths, the number of firms, and the shape of the load curve, are specific to a particular area. Colorado serves as a case study for this analysis. The

approach implemented here is to compute a competitive market equilibrium using a simulation model, and then apply a dominant firm's markup when the supply of the competitive fringe is constrained. The model shows that the incumbent regulated monopoly, Public Service Company of Colorado (PSCo), has the potential to set prices above marginal cost much of the year. The price elasticity of demand, which varies by customer class, also greatly affects the amount of markup PSCo could apply. The study investigates three scenarios under which PSCo's market power might be mitigated. Relaxing transmission constraints within the Rocky Mountain Power Area has almost no effect on PSCo's market power. Entry by 1,000 MW of fringe generation reduces the amount of the year over which a markup could be applied from the base case estimate of 93% to 72%. If PSCo agrees to divest 50% of its generation, markups can be applied only 37% of the year.

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Chapter 1

INTRODUCTION AND PROBLEM STATEMENT

Most Americans take the universal, reliable delivery of relatively cheap electricity for granted. The impact of major outages, though, such as the two that occurred in the Western United States in July and August 1996 bring our society's reliance on electricity into focus (WSCC 1996a, 1 and 1996b, 1). The value of society's investment in the infrastructure involved in the delivery of electricity is over $400 billion (Sitzer, 1997); annual retail U.S. electricity sales total over $208 billion (EIA 1996a, 5).

Now some states are implementing, and most are considering, programs to permit some degree of competition in what has been called "the last great regulated monopoly" (EIA 1996b, ix). Following the lead of the United Kingdom, Norway, Argentina, Australia, and New Zealand, these states hope that competition will bring lower costs and increased choices for all consumers. This movement has gained such momentum that some observers view the question of

restructuring not as a matter of "if," but of "how and when" (Costello and Rose 1997, 1).

Under most electric restructuring proposals, competition occurs in the generation of electricity. However, even generation must remain regulated to the extent necessary to ensure reliability of service. Transmission and distribution remain regulated monopolies subject to some form of cost-of-service or performance-based regulation. In some respects, electric restructuring can merely be viewed as trading one regulatory regime for another, or what some call "re-regulation" (Taylor 1996, 63).

"Deregulation of the electric utility industry represents an enormous opportunity to mismanage a massive amount of financial and engineering assets with socially detrimental repercussions" (Backus and Baylis 1996, 9). Implementing electric restructuring in generation requires that policy makers appropriately address a myriad of legal, economic, and engineering issues. Would, for instance, the requirement for an incumbent electric monopoly firm to divest a portion of its operations constitute a takings prohibited by the Fifth Amendment? How should a competitive market for generation be organized? How will system reliability be maintained in a competitive environment?

One of the key issues in moving from regulation to a restructured framework is how quickly competitive markets for generation would develop. Competitive markets would ensure that electricity is delivered at the lowest possible price. Competition would pressure incumbent monopoly firms to become more efficient and improve service to customers. However, legislation to implement electric restructuring might not necessarily guarantee the creation of competitive generation markets.

During the transition from a regulated market to competitive markets, some firms might have the opportunity to exercise market power. Market power simply is the ability of a firm to profitably charge prices in excess of marginal cost by withholding generation from the market (Joskow 1995, 11). Economic theory suggests that the problem is self-correcting over time (Baumol 1982, 2). If a firm exercises market power to make economic profits, this will encourage other firms to enter the market. Eventually, competition will increase and prices will be driven down to competitive levels.

Therefore, the problem of market power, from an economic perspective, is a "short run" concern. Given the generation and transmission capacity that exists at the time

electric restructuring is implemented, can one firm, or a group of colluding firms, set market price above marginal cost? In the "long run," when new generation and transmission can be constructed, economic theory suggests that competitive markets will prevail, and firms will price at marginal cost. However, it appears that the "long run" for restructured electricity markets may take a long time to arrive.

In the United Kingdom, competition in generation was introduced in 1990. Even today, the two largest generation firms in the UK are still able to strategically manipulate prices. Market power persists despite repeated attempts by the Director General of the Office of Electricity Regulation (OFFER) to mitigate its effects (Wolak and Patrick 1997, 51). While restructuring in the UK has produced many benefits, such as less pollution and increased labor productivity within electric utilities, it has not resulted in lower generation prices for all customers. Instead, lower costs have translated into higher utility profits; utility stock prices have increased by 250% over the past five years, outperforming the UK stock market by 100% (Newbery and Pollitt 1997, 2).

Legislators in states that are debating the implementation of electric restructuring therefore face common concerns related to market power in generation:

1. If restructuring is implemented, can a firm or firms exercise market power in the "short run?"
2. If market power is a problem, by how much will market price exceed marginal cost?
3. What policies can be effectively implemented by state policy makers to mitigate the effects of market power?

The research presented in this paper will address these issues. However, analysis of these issues cannot be separated from the circumstances of each state considering restructuring. The existing number of monopoly firms, the transmission grid, and the composition of demand by customer classes all help determine the potential effects of market power. Therefore, this analysis will present one approach to analyzing and mitigating market power, using the state of Colorado as a case study.

As in many other states, legislators in Colorado are grappling with the decision of whether to restructure, and, if restructuring occurs, what form it should take. In

Colorado, restructuring bills have been introduced in the last two sessions of the Colorado legislature. Both failed to win passage. With the approval of restructuring legislation in nearby Montana and the completion of a restructuring study in Wyoming, the issue will undoubtedly be considered in future sessions of the Colorado legislature.

An analysis of Colorado's restructuring issues may provide insights to other states considering restructuring. Each of the major types of electric utilities has a strong presence in Colorado: investor-owned utilities (IOUs), rural electric cooperatives (RECs), and municipal power companies. The Western Area Power Administration (WAPA), a federal power agency, provides a significant amount of generation. There is a varied mix of generation, including coal-fired stations, hydroelectric facilities, oil-fired and natural gas plants. The transmission network in Colorado is usually adequate for electricity to be imported from other states. However, certain conditions also create transmission constraints that isolate Colorado's market. Demand is divided fairly equally among large industrial, commercial, and residential customers, so large customers do not dominate the market.

State policy makers need to know if electric restructuring could result in lower prices for all consumers. If incumbent monopoly firms do not face sufficient competition when restructuring is implemented, then it may be a long time before consumers enjoy the benefits of restructuring. This analysis addresses this concern. Chapters 2 and 3 provide an overview of restructuring issues most pertinent to the analysis of market power and then detail the specifics of the Colorado electricity market. Chapters 4 through 6 will summarize the research of others in addressing market power, explain the economic conceptual framework for the analysis, and propose a methodology to analyze market power. Chapter 7 summarizes the findings of this analysis. Chapter 8 details the study's policy implications and suggests avenues for further research.

This analysis intends to address the issues faced by state policy makers in the following way:

1. Develop a model of a restructured Colorado electricity market, given current generation and transmission, to forecast prices if effective

competition in generation exists and firms price at marginal cost.

2. Modify the model to permit firms with market power over generation to charge prices in excess of marginal cost. These prices will be compared to competitive prices to gain a measure of potential inefficiencies in a restructured market.
3. Analyze scenarios in which the market power of the incumbent monopoly might be mitigated. Then market prices will be re-estimated and compared to prices estimated in steps 1 and 2.

This research is intended to provided insights to state policy makers considering restructuring. Some restructuring studies assume that the introduction of competition will result immediately in generation pricing at marginal cost. This paints an overly optimistic picture of how prices will respond to electric restructuring. When firms are able to exercise market power, the assumption of marginal cost pricing could be in error, with potentially costly results to electric consumers. This research is less concerned with the prediction of prices than estimating whether a firm with market power in generation can charge prices in excess of

marginal cost. When market power does appear to be a problem, there may be effective ways to mitigate it. This paper will consider some of these options.

Chapter 2

ELECTRIC RESTRUCTURING AND MARKET POWER

Over the past twenty years, Americans have seen a number of industries deregulated to some extent, including airlines, telecommunications, trucking, railroads, and natural gas. In each case, government regulation in the face of so-called "natural monopolies" gave way to environments that are largely competitive, providing real price reductions for most consumers (Crandall and Ellig 1997, 2). Many states are now attempting to deregulate portions of the electric utility industry. "Electric restructuring" refers to attempts to create a competitive market for electric power generation and energy services, which include metering, billing, and demand management. "Electric restructuring" is a more commonly used term than electric deregulation. Although competition will occur in some aspects of the provision of electric service, most plans for restructuring continue to view the transmission and distribution of electricity as natural monopolies (Texas PUC 1997, ES-7).

The traditional vertically integrated electric utility controls three major functions: generation, transmission, and distribution (figure 1). Generation comes from a

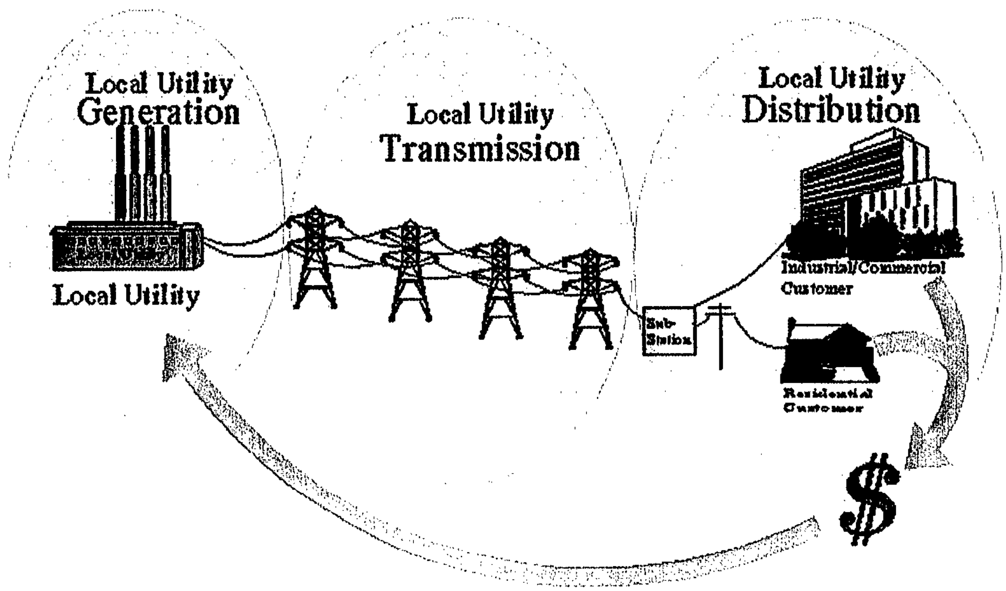


Figure 1. Traditional vertically integrated utility.

variety of sources: plants that each company owns; contract power from independent power producers and other utilities; federal power agencies, such as the Western Area Power Administration (WAPA); and wholesale short-term purchases from the spot market for electricity. Transmission refers to high-voltage lines that carry power over long distances. While the interconnected transmission network functions as a

unified system, the individual lines may be actually owned by many separate firms, including integrated utilities, federal power agencies, and transmission companies. Distribution refers to lower voltage lines that carry power from the transmission network into individual homes and businesses.

State governments historically have granted utilities monopoly franchise over their service area and the opportunity to earn a fair rate of return on their capital investment. In return, utilities submitted to rate regulation, provided universal service to all customers in their service area, met requirements for reliability of service, and supported a variety of other programs, including assistance for low-income customers and energy conservation.

Under restructuring, electric utilities must functionally separate these three business activities. The goal of functional separation is to eliminate vertical sources of market power. For instance, billing information from the distribution function could give a firm a competitive advantage when it bids to service a particular customer. Efficiencies of scope arise from control of the generation and transmission functions. With functional

separation, the utility would not be permitted to favor its own generation, for instance, over any other firm competing in the market.

Under restructuring, firms will compete primarily in the generation of electricity. Competition in generation has emerged through the development of new technology that has dramatically lowered the cost of generation and capital requirements (figure 2). Over the past 70 years, the average cost of generation per megawatt at the plant level has steadily declined. In the last ten years, with the development of combined cycle gas turbine generators, the minimum efficient scale of operation for a generation plant (the low point of each cost curve) has dropped dramatically. This technological advance means that the market for electricity generation can now include many small competitive firms. Formerly, the scale of efficient operation was so large and required such a large capital investment that a regulated monopoly was the least cost industry structure. Now, with the optimal plant size much smaller, the capital cost required to enter the market is lower.

The growth of interest in combined cycle gas turbines is aided by a dramatic decrease in the price of natural gas

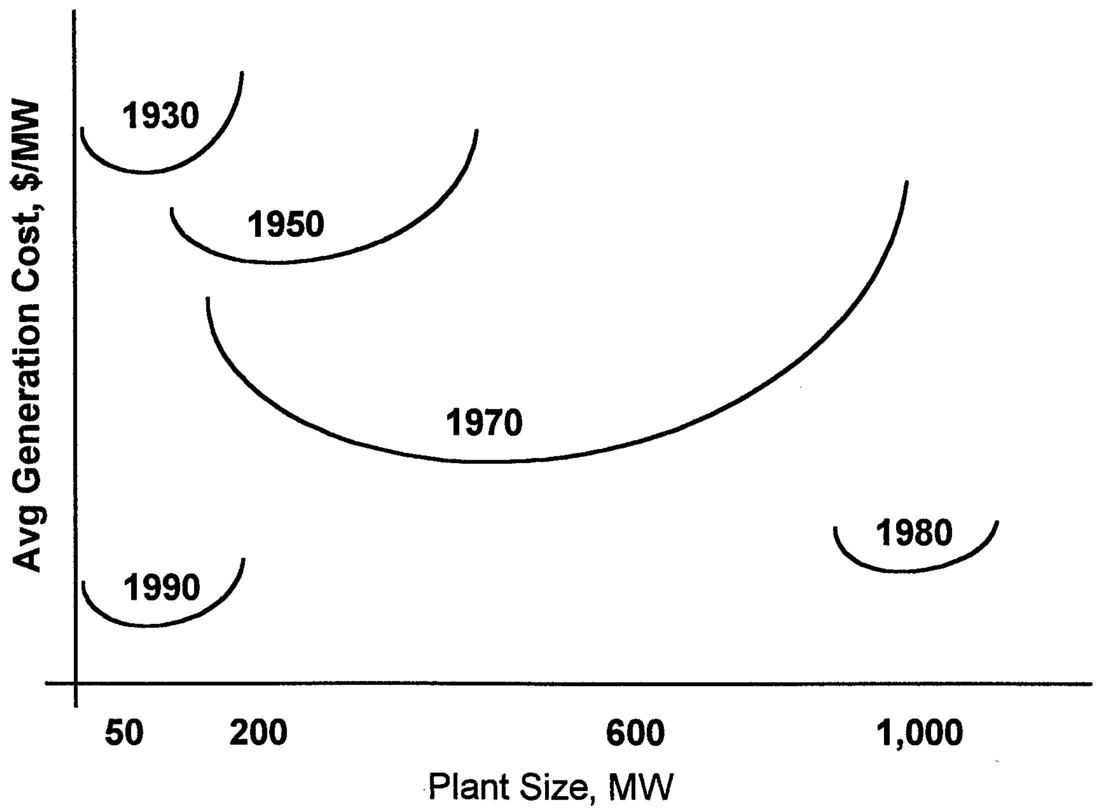


Figure 2. Optimal generation plant size for a single plant based on cost per megawatt (MW), 1930-1990.

Source: Bayless 1994, 21.

over the last decade. Price has fallen from a high of $4 per thousand cubic feet of natural gas in the early 1980s to recent lows in the range of $2 per thousand cubic feet (EIA 1997a, 57). Furthermore, these prices are expected to remain low for some time. Technological progress in the discovery process has increased reserve estimates. Declining drilling costs are also expected to keep prices low (EIA 1997a, 58). While prices for natural gas have also demonstrated some volatility, much new generation construction is natural gas, perhaps reflecting a belief that gas prices will remain low enough to make this generation competitive for the foreseeable future.

Furthermore, excess generation capacity, a legacy of over-building that occurred in the 1970s, will ensure excess generation is available for purchase over the transmission grid for a few more years. In the 1970s, rosy predictions of ever-increasing electricity demand produced a boom in generation construction. Two oil shocks later, the growth of demand markedly declined. Capacity exceeded demand in some regions by as much as 30% (EIA 1996b, 5). This excess capacity stimulated competition in wholesale markets, keeping generation costs low. Demand growth and generation

retirements will eventually eliminate this excess, driving down generation capacity to minimum reserve margins.

Since the cost of generation is the largest component of electricity prices, competition in generation has significant potential for lowering consumer prices (figure 3). The new technology has other benefits as well. Since combined cycle gas turbines are fueled by natural gas instead of coal, they emit fewer pollutants. Additionally, a larger number of small generators spread across the transmission grid, instead of a few massive coal-fired stations, increase system reliability and reduce transmission constraints.

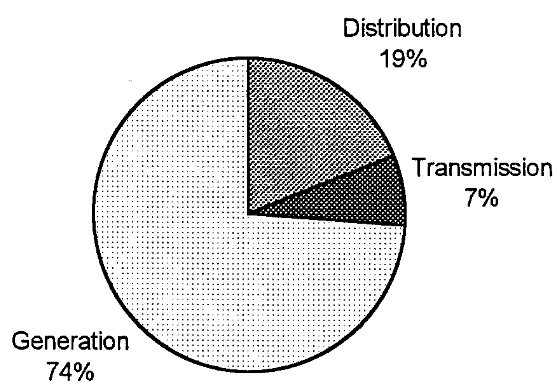


Figure 3. 1995 average cost of U.S. electricity by function.

Source: EIA 1997c, 11.

Restructuring Legislation

As of February 1, 1998 ten bills were pending in the U.S. Congress that would direct states to implement restructuring. Congressman Dan Schaefer (R-CO) has introduced the "Electricity Consumers' Power to Choose Act" which would require states to give all consumers the right to choose their supplier of electricity services by December 15, 2000 (EIA 1996b, 49). Other national bills are being considered in the House and Senate that mandate restructuring on timelines ranging from 1998 to 2010.

The prospect of a federal mandate is an incentive for states to pass their own bills so they can tailor their restructuring plans to local needs. As of February 1, 1998, ten states had enacted legislation to restructure. Many other states have ongoing studies and pilot projects (NRRI 1998, 3). The restructuring movement initially gained support in the Northeast and California, areas with high cost electricity (figure 4). In these states, a number of regional electric utilities can compete for customers in a restructured environment. Proponents of restructuring argue that the presence of competition in generation should pressure former monopolies to become more efficient and

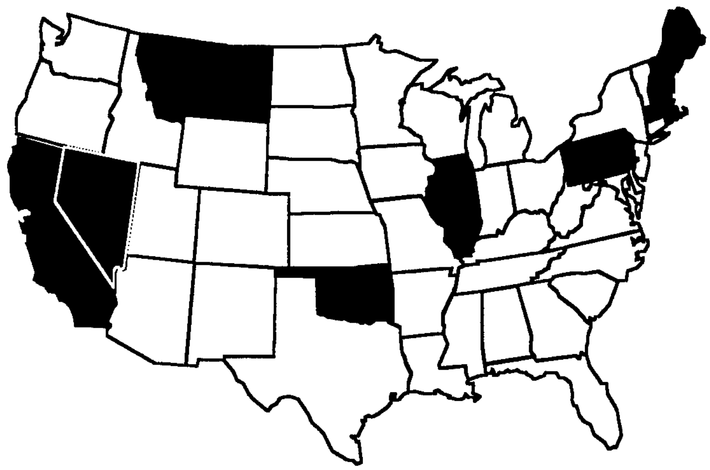


Figure 4. States implementing restructuring as of February 1, 1998.

Source: NRRI 1998, 1.

reduce their generation costs (Competition Policy Institute 1997, 7).

The transmission grid in these states also promotes competition. There are multiple transmission paths with enough capacity to make the market for generation "contestable." Competing utilities over a wide area are able to use the transmission grid to enter any market where they can provide power at lower cost. This threat of entry disciplines incumbent monopolies with a long term perspective from charging excessively high prices (Borenstein, Bushnell, and Stoft 1997, 2).

The threat of competitive entry up to the level permitted by the existing transmission grid is available immediately upon the implementation of electric restructuring, or in the "short run." It contrasts with the long-run threat of entry by firms who might enter the market through the construction of new generation or new transmission paths. At the very least, new generation takes 20 months to site and construct (PSCo 1997, 3). Because of required environmental approvals, new transmission capacity would take much longer.

The recent passage of restructuring legislation in Montana and Oklahoma breaks the pattern of restructuring in states with high electric rates where competition might be expected to flourish. In Oklahoma and Montana, electricity prices are relatively low (figure 5). Their transmission networks may not facilitate entry into their electric market by out-of-state firms. This may limit free entry and exit by out-of-state generators who wish to sell their output in these states. These factors may create conditions where the incumbent monopoly might be able to exercise market power once a state implements restructuring.

There is another important difference between Oklahoma and Montana, and those states that initially were in the

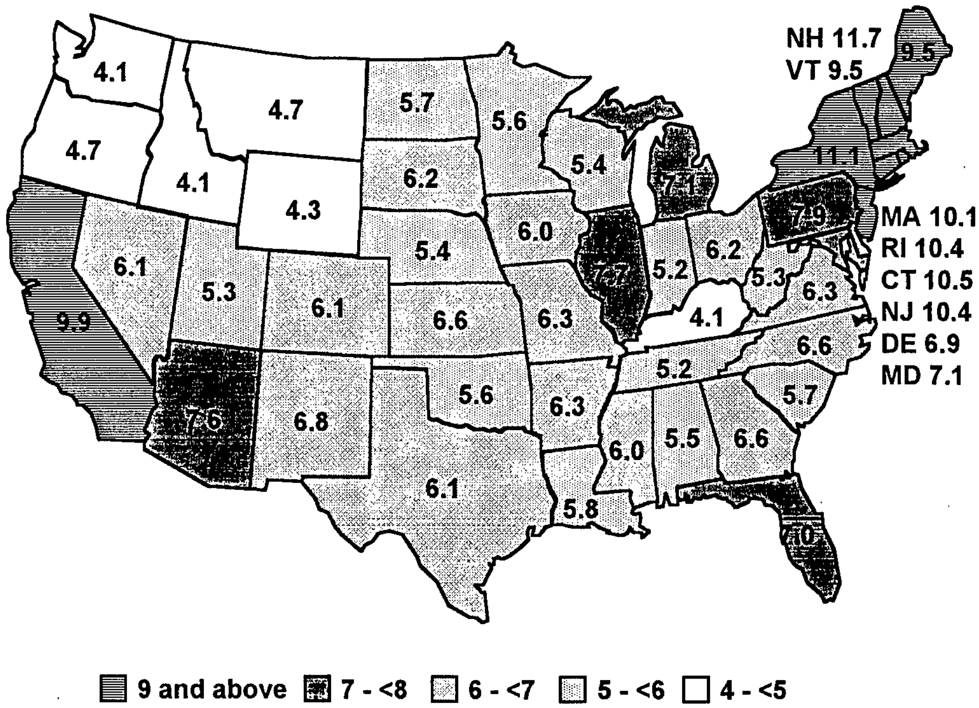


Figure 5. Average revenue from electricity sales to all retail customers, cents/kWh, by state, 1995.

Source: EIA 1996a, 39.

lead in implementing electric restructuring. In California, at least three large, formerly regulated investor-owned utilities could be expected to compete in a restructured generation market. Many other states have only one large regulated electric monopoly. In twenty states, one firm owns over half the existing generation. In twelve states, one firm owns between 40% and 50% of existing generation (table 1). As these states consider plans to implement

Table 1.

States in Which a Dominant Firm Owns More Than 40% of Generation Capacity

State	Share	Utility
Alabama	57%	Alabama Power
Arizona	42%	Arizona Public Service
Arkansas	79%	Arkansas Power and Light
Colorado	51%	Public Service Company of Colorado
Connecticut	40%	Northeast Nuclear Energy
Delaware	90%	Delmarva Power and Light
Florida	43%	Florida Power and Light
Georgia	85%	Georgia Power Co.
Hawaii	72%	Hawaiian Electric Co.
Idaho	48%	Idaho Power Co.
Illinois	67%	Commonwealth Edison
Maine	57%	Central Maine Power Co.
Maryland	49%	Baltimore Gas and Electric
Michigan	48%	Detroit Edison
Minnesota	71%	Northern States Power
Missouri	46%	Union Electric
Montana	60%	Montana Power Company
Nebraska	47%	Nebraska Public Power District
New Hampshire	46%	North Atlantic Energy Service Corp.
New Jersey	74%	Public Service Electric and Gas
New Mexico	41%	Arizona Public Service
North Carolina	54%	Duke Power Co.
Oklahoma	47%	Oklahoma Gas and Electric
Oregon	66%	USCE
Rhode Island	96%	Northeast Power Company
South Carolina	44%	Duke Power Co.
South Dakota	58%	USCE
Tennessee	97%	TVA
Utah	53%	Pacificorp
Vermont	50%	Yankee Nuclear
Virginia	83%	Virginia Electric and Power Co.
Wyoming	66%	Pacificorp

Source: EIA 1997b, Table 20.

electric restructuring, the potential market power of the formerly regulated electric monopoly must be of greater concern.

Market Structure

Competition is expected to stimulate innovation by firms offering products in the marketplace, increase efficiency in generation, and reduce prices for consumers. This analysis is concerned primarily with the potential for competition to reduce price. Competitive prices are expected to be lower because they reflect the marginal variable costs at a given level of demand. In contrast, regulated prices are based on average total costs, fixed and variable.

Fixed costs, such as required portions of fuel contracts, administrative expenses, most labor, and some maintenance, must be paid whether or not a particular plant generates any electricity. Variable costs, such as fuel, are incurred only if the plant generates electricity. The distinction is important because a competitive firm will choose to sell generation whenever market price exceeds variable generation costs.

Once variable costs are paid, any additional revenue allows the firm to recoup its fixed costs. In a competitive market, price equals marginal cost, which includes the cost of fuel and variable operations and maintenance (O & M) costs at the plant with the highest costs supplying the market at a given time. All of the plants with lower variable costs are earning revenue in excess of their variable costs, which pays some portion of their fixed costs and a return on capital invested.

The quantity of generation supplied by firms is represented by a market supply curve (figure 6 shows a generic example). At low prices, only the cheapest sources

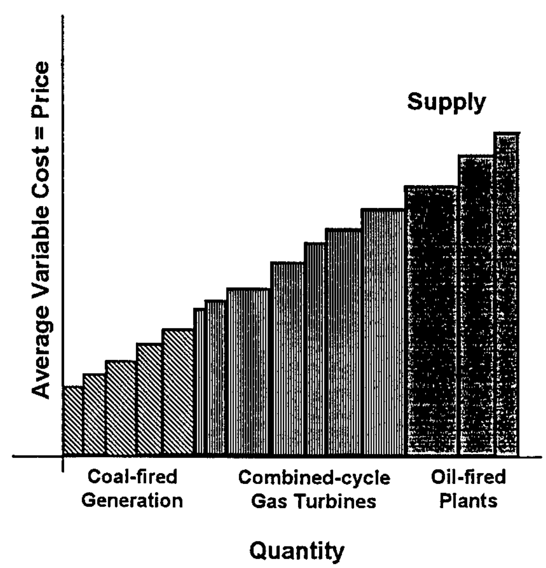


Figure 6. Supply curve for generation.

of electricity can operate and cover their variable costs, so the quantity supplied is low. At higher market prices, firms are able to operate additional generators with higher variable operating costs, which increases the quantity supplied to the market.

In the generation market, the supply curve is typically represented as a step function (Green and Newbery 1992, 933). Each step represents the capacity supplied by the next most expensive plant at its average variable cost of generation. Strictly speaking, economists would prefer to equate price with marginal cost, but empirically, average variable cost at the plant level provides a good approximation for an industry supply curve (Borenstein and Bushnell 1997, 37). The supply curve for a given market represents all of the plants capable of supplying electricity in that market, given existing transmission constraints.

When markets are at a competitive equilibrium, the quantity supplied equals the quantity demanded by consumers (Q_c) (figure 7). The market price (P_c) represents the value to consumers of the last unit purchased, or their marginal willingness to pay. From the firm perspective, market price equals the average variable cost (as a proxy for marginal

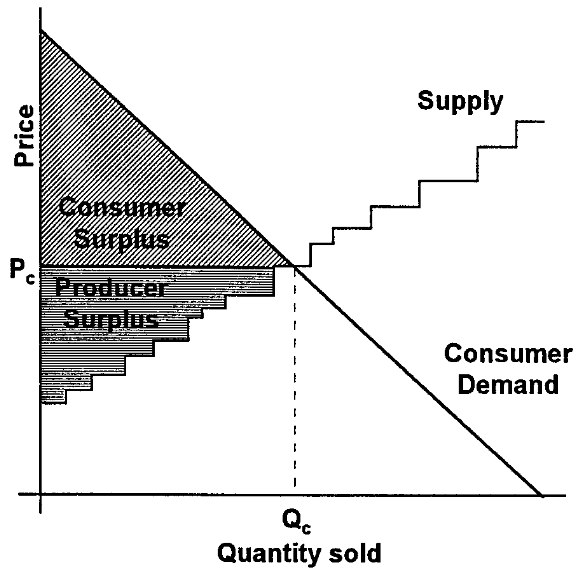


Figure 7. Competitive market outcome.

cost) of the last unit produced. Consumers earn a benefit called consumers surplus, which represents the difference between the price for the last unit purchased and the amount they would have been willing to pay for each unit up to the last unit purchased.

When the market price equals the marginal cost of the last unit produced, producers may still be able to earn profits (economic rents) from their low cost generation. The profits that producers earn, or producers surplus, represent their revenues ($P_c \times Q_c$) minus their costs of production. Together, consumers surplus and producers

surplus represent the net social benefits of the competitive marketplace.

If an incumbent monopoly, either by itself or by colluding with a small group of firms, is able to exercise market power, it will reduce quantity supplied (Q_m) and increase price (P_m) (figure 8). Total profits, which are the excess of total revenue ($P_m \times Q_m$,) over costs (the area under the supply curve), increase. These increased profits represent a transfer of wealth from consumers to firms.

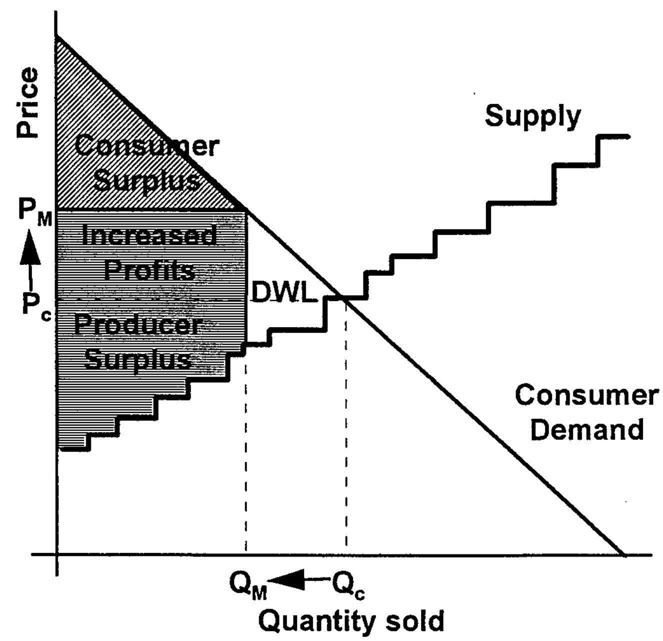


Figure 8. Market outcome when market power exists.

From an economic perspective, the transfer of wealth, by itself, does not represent a decrease in net social benefits, although it does raise a question of fairness or equity. However, there is a reduction in net social benefits due to reduced production, which is referred to as a deadweight loss (DWL). This deadweight loss is a potential economic inefficiency from the exercise of market power because society's factors of production are not put to their most efficient use.

On the supply side of the problem, the ability of a firm, or group of firms, to exercise market power is limited in the short run by the ability of the other generation firms to increase output (their price elasticity of supply, $\varepsilon_{S,P}$) (Werden 1995, 15). "Short run" refers to the current market conditions, assuming existing firms, generation, and transmission. If a dominant firm, or cartel, attempts to reduce quantity supplied to increase prices, and its competition is able to increase output back to a competitive level, the chance to exercise market power is limited (Borenstein, Bushnell, Kahn, and Stoft 1996, 15). In electric power markets, this is why transmission capacity plays a key role. The transmission network gives firms with

excess generation the opportunity to enter markets anywhere on the grid whenever a firm attempts to exercise market power.

The ability of a firm to exercise market power is limited in the long run by the entry of new firms (Joskow 1997, 134). The "long run" assumes a time span sufficient to permit the construction of new generation or transmission lines. The chance to make a profit provides incentives for firms to construct new generation. As entry by new firms continues, the market share of the firm(s) attempting to exercise market power declines. Economic theory suggests that entry will continue until price equals the marginal cost of new generation and competitive conditions prevail (Newbery 1995, 54). Unfortunately, it might take a long time for the "long run" to arrive. Newer technology combined-cycle gas turbine plants require a minimum of 20 months to become operational (PSCo 1997, 3). In the meantime, consumers suffer from higher prices while awaiting the benefits of competition.

The ability of firms to exercise market power is also influenced by the way consumers adjust their demand in response to a change in price (their price elasticity of demand ($\varepsilon_{q,p}$). If demand is elastic ($\varepsilon_{q,p} > |1|$), a 1%

increase in price would result in a greater than 1% reduction in quantity demanded by consumers (figure 9).

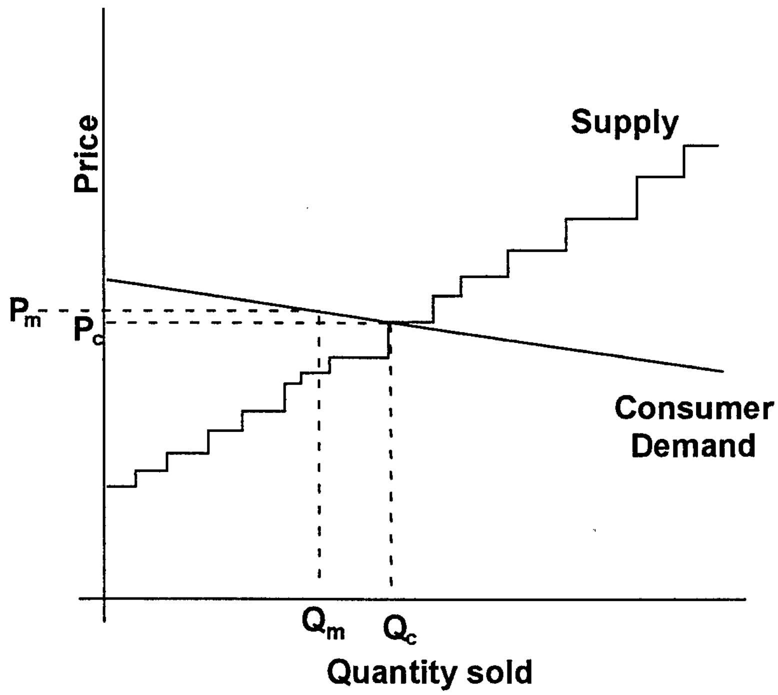


Figure 9. Elastic demand.

Firms wouldn't increase price because consumers would reduce demand by a proportionately greater amount. The price increase would cause total revenue to decline. On the other hand, if demand is inelastic ($\varepsilon_{q,p} < |1|$), a 1% increase in price would result in a reduction in quantity demanded of less than 1%, so a firm could increase its total revenue by increasing prices (figure 10).

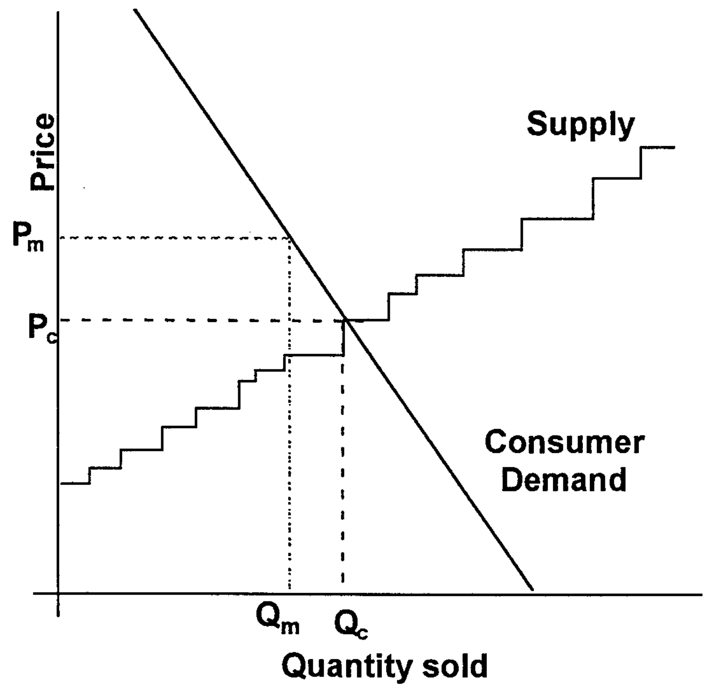


Figure 10. Inelastic demand.

The demand response of consumers is significant in the electric industry because in the short run, demand is very inelastic. Studies typically estimate the price elasticity of demand for electricity between |0.1| and |1.0| (Borenstein and Bushnell 1997, 18). Furthermore, the price elasticity of demand may vary significantly by class of customer. Large industrial customers have the option of installing their own generation, adjusting production schedules to use the cheapest source of electricity, or even building their own transmission links to low-cost generation. Large

customers, because they have higher demand, may also enjoy greater competition for their business than small customers. In contrast, residential and small commercial customers may have fewer substitutes for generation, and hence, a lower price elasticity of demand.

A firm with market power may be able to take advantage of these differences in demand to develop a non-linear pricing schedule, such as offering quantity discounts, that would allow it to earn the highest possible profit from each customer class (Baumol and Bradford 1982, 267). Residential and small commercial customers could face much higher prices than industrial customers. The same type of disparity could exist between large industrial and rural customers.

An analysis of market power becomes more complex when the dynamic nature of the marketplace is considered. Given current technology, electricity cannot be stored economically on the transmission grid. There is no inventory of generated electricity available to serve as a buffer to fluctuations in demand. Supply and demand must continually balance. Each time a consumer turns on a light switch, or more significantly, every time an arc furnace turns on in a steel mill, generators must be available immediately to increase output. There are daily variations

in demand, as people wake up, go to work, and come home. There are also seasonal variations in demand to provide, for instance, heating in the winter and cooling in the summer (figure 11). Supply response must be immediate. If an increase in quantity demanded causes a much more expensive generator to begin production, price could jump greatly.

The requirement for supply and demand to be in balance continually also means that some reserve margin must always be available to immediately provide power, either in response to an increase in demand or in case another plant providing power to the system fails. The supply side of an analysis of market power must also consider the generation that must be set aside for this purpose (EPRI 1996, 7-12).

The reserve margin helps ensure the reliable delivery of electric power. Reserves vary by their states of readiness. "Spinning reserves" are available to provide immediate power to the system. Fast reserves are on-call plants available to provide power to the system within ten minutes of notification (EPRI 1996, 7-5). Firms providing power to the network maintain reserve requirements in accordance with voluntary industry compacts. In a restructured environment, these compacts are expected to continue in some form, as a requirement for access to the

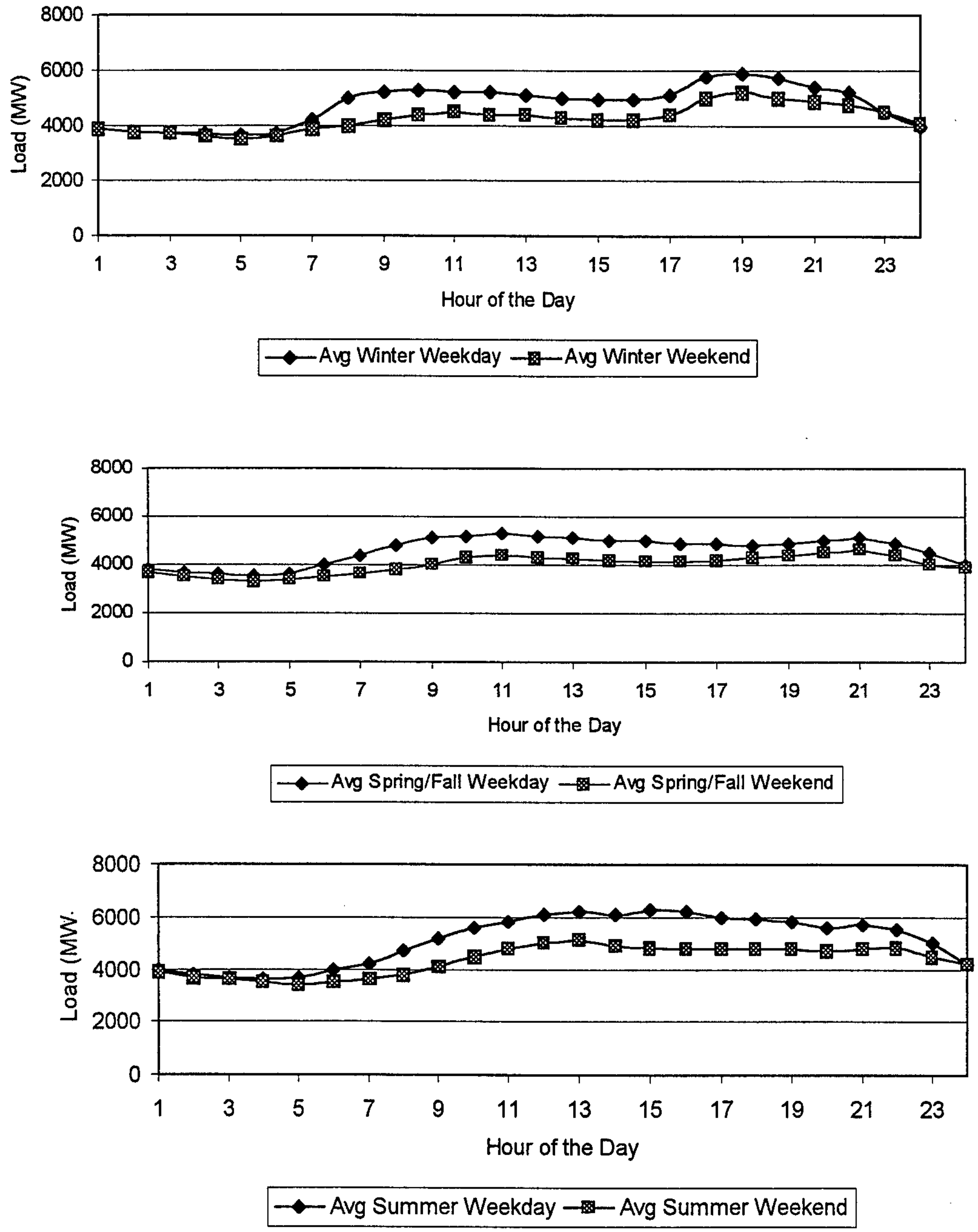


Figure 11. Variations in electricity demand within the Rocky Mountain Power Area (RMPA), 1995.

<u>Source</u>: RDI 1997, R-6.

transmission grid (NERC 1997, 17).

Generation supply is also affected by the availability rate of generating stations. Typically, these have an annual availability rate in the range of 80%-90%. Utilities must schedule "down-time" periodically to perform maintenance on these systems. In a regulatory environment, it was not unusual for utilities to cooperate in scheduling maintenance periods, so that reliability of the system was not affected. Whether or not this spirit of cooperation will continue under restructuring, or whether cooperation must be mandated as part of an agreement to have access to the transmission grid remains to be seen (WSCC 1997a, 1). In addition to scheduled maintenance, components of generating stations periodically fail and require emergency, unscheduled maintenance. The availability rate of generating stations, therefore, may sometimes have a significant impact on the supply of electricity.

The Role of Transmission in Market Structure

The dynamic nature of the equilibrium price-quantity combination causes the transmission network to play a significant role in an analysis of market power. When the transmission network is not constrained, firms can provide

power to customers over a wide area so long as generation capacity is available and engineering requirements associated with the operation of the transmission grid are not violated. However, when transmission paths are fully loaded, smaller regional markets may develop, which might give firms the opportunity to exercise market power within their local area.

The United States is divided into three major transmission networks, the Western Interconnect, the Eastern Interconnect, and the Electric Reliability Council of Texas (ERCOT) (figure 12). These transmission grids developed

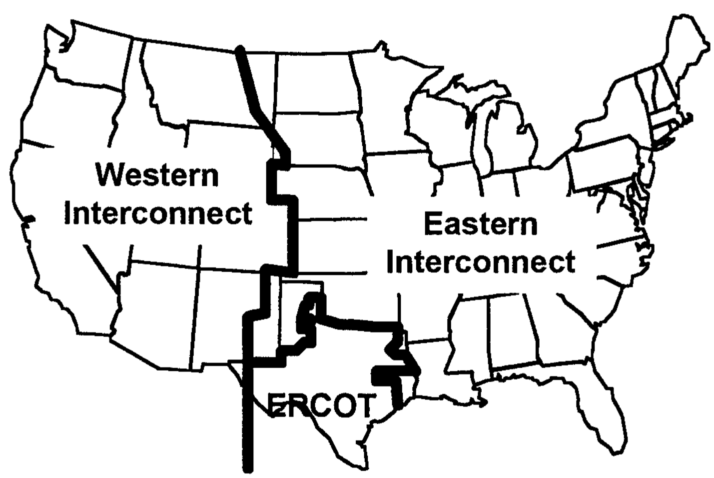


Figure 12. Major U.S. interconnects.

Source: National Council on Competition and the Electric Industry 1996, 9.

over the twentieth century as electric service gradually expanded nationwide from each coast. Today, the divisions remain in effect to increase efficiency and to enhance reliability.

Over the course of each day, peak demand shifts from east to west across the country, during the course of the workday, and as the sun passes over each area of the country. The divisions in the grid make it easier to manage the flow of power. These divisions also enhance reliability. If a major disruption of service occurred in one area of the country, the entire country would not be affected. The links between the three regions are limited. For example, the peak demand on the Western Interconnect in 1996 was 123,375 MW (WSCC 1997c, 5). The total transmission capacity between the Western region and the rest of the country is only 930 MW.

Within each interconnect, high voltage transmission lines carry electric power over long distances (figure 13). These lines are owned by a patchwork of investor-owned utilities, municipal power companies, rural generation and transmission cooperatives, and federal power agencies. The transmission network serves several functions. In some areas, transmission may substitute for the construction

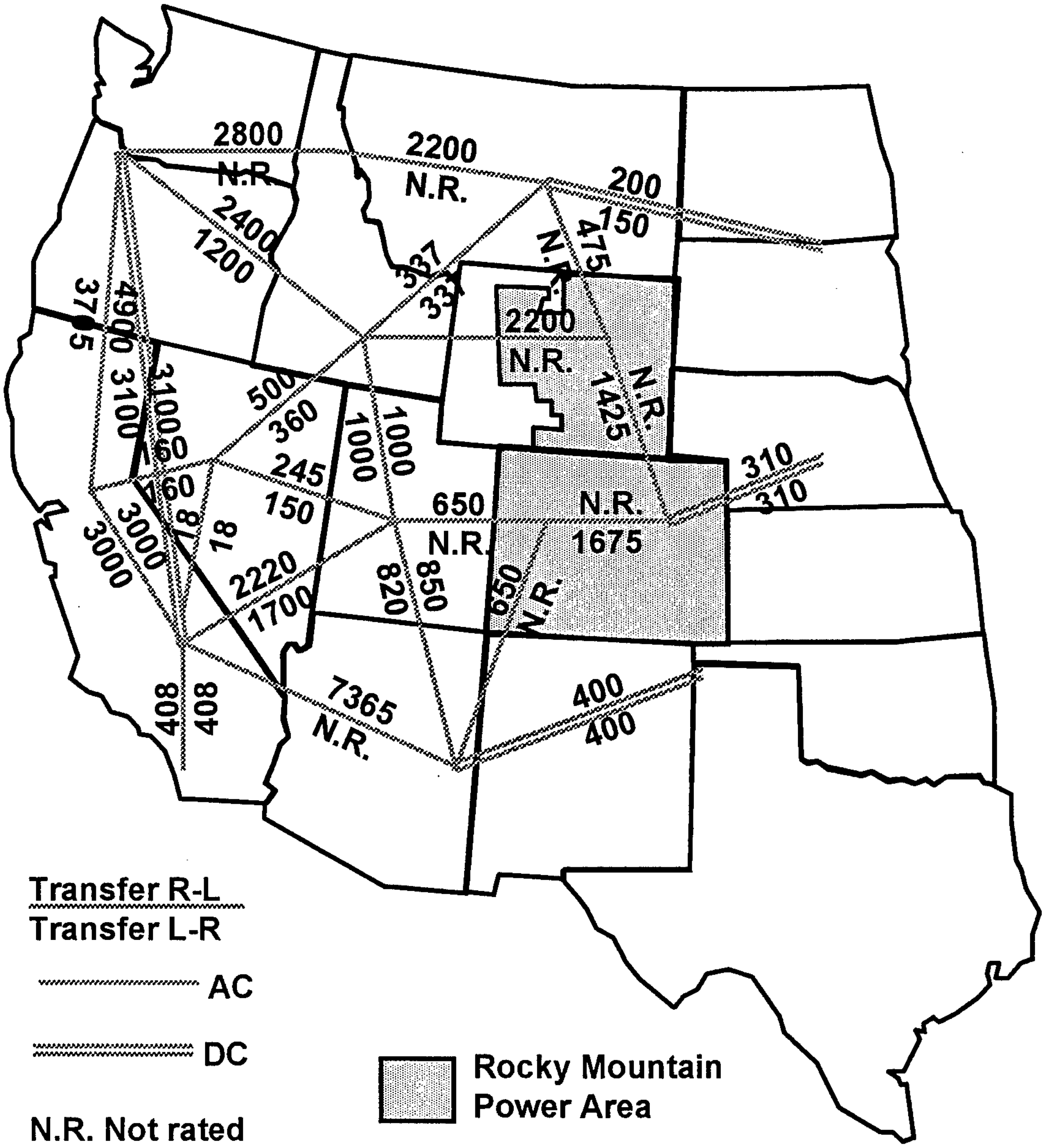


Figure 13. Western transmission paths.

Source: WSCC 1997b, 64-65.

of new generation, by allowing distant firms to enter a market and satisfy excess demand. The ability to transmit electricity over long distances also allows plants to be constructed where the costs of generation are low, such as near cheap sources of hydroelectricity, or at a source for low-cost coal (Cardell, Hitt, and Hogan 1996, 6). This power can then be transmitted over the grid to areas where demand is high, such as population centers or centers of industrial activity.

Power transmission entails two costs to generators. Power is lost in the transmission process in proportion to the distance it is transmitted. Higher voltage lines will reduce losses, but losses can never be eliminated. Secondly, owners of transmission lines impose a charge per megawatt to transmit power over their lines. The Federal Energy Regulatory Commission's Order 888 requires that all firms be granted non-discriminatory access to the transmission network (EIA 1996b, 29). This order prevents a vertically integrated electric utility from giving preference to its own generation. Even with non-discriminatory rates, the existence of these transmission charges may reduce the competitiveness of electric power transmitted over long distances. Furthermore, as electric

power passes from lines owned by one firm to lines owned by another firm, additional transmission charges are imposed. These charges become "pancaked," or added to one another, as electricity moves from the transmission lines of one company to another across the grid.

For market power analysis, it is also important to note that the existing transmission grid was constructed in a regulatory environment to facilitate the transmission of power by monopoly firms. The transmission grid was never intended to promote a freely traded market for generation. Incumbent monopoly firms may possess a competitive advantage in their local markets simply by the location of the plants they currently own in relation to the existing transmission paths and capacity of the grid. The physical characteristics of the transmission grid may, in fact, require that some plants must operate to maintain proper voltage in a particular area. The owners of these plants will have a competitive advantage (EPRI 1996, 7-21).

The importance of transmission capacity in mitigating market power in generation is also affected by the availability of excess power on the grid that can be "wheeled" from one region to another. In part, the existence of excess capacity is a continuing legacy of

overbuilding that took place in the industry in the 1970s. The two oil shocks that occurred then caused electricity prices to jump and consumers to reduce quantity demanded. As a result, many utilities had significant excess capacity. Excess capacity has contributed to the competitive market that exists for wholesale power. Gradually, however, demand growth will eliminate this excess capacity in many areas of the country. The absence of excess power could reduce opportunities to wheel power over the grid from one region to another and reduce the role transmission capacity can play in mitigating market power in generation.

Mitigating Market Power

At least four approaches are available to state policy makers to mitigate the market power of incumbent monopoly firms. These may be employed singly or in concert with one another.

1. Require incumbent monopoly firms to divest all of their generation or some portion of it. Dominant firms would voluntarily agree, or be required, to auction off a portion of their generation. This would create enough firms to set the conditions for a competitive market. Under

California's restructuring plan, for instance, incumbent monopolies voluntarily divest 50% of their fossil-fueled generation in return for the opportunity to earn unregulated profits (California PUC 1997a, 1, and 1997b, 1). This action is the result of an agreement between the firms and state government.

2. Enlarge the market by adding transmission capacity. This could increase competition from distant firms who wish to compete in local markets. Additional transmission capacity makes the market more contestable. Firms would have difficulty increasing prices because distant firms could easily enter the market at a lower price by way of the transmission grid. Even if no power actually flows over the transmission grid, transmission investments may be worthwhile because they keep prices down (Borenstein, Bushnell, and Stoft 1997, 4). Distant firms would incur some additional costs due to transmission charges and the loss of power (typically 3-7%) which occurs as a result of the transmission process. The construction of new transmission capacity is expensive and subject to lengthy environmental impact assessments (Fuldner 1997, 1). For this reason, the construction of new transmission paths would probably not be a short-run solution to market power

problems. Fortunately, technological developments are becoming available which increase the capacity of existing lines. This might be a feasible short-run option.

3. Implement measures to increase the propensity of customers to adjust demand in response to changes in the price of electricity, that is, make demand more "elastic." This could be done, for instance, by providing more sophisticated billing that reflects "time of day" variations in pricing, or promoting the installation of smart appliances or thermostats that reduce consumption of electricity during peak demand periods.

4. Impose price caps until effective competition develops (continued regulation). A state agency, typically the state Public Utilities Commission (PUC) could be charged with the responsibility of monitoring the development of competition. Legislation might include provisions for price caps on electricity prices during some established transition period. This approach is also part of California and Montana's plans.

Inefficiencies of Regulation

Given all of these factors that contribute to market power, it would be surprising if an incumbent monopoly

generation firm was not able to exercise market power in a restructured electricity market. However, the existence of some degree of market power in a restructured electric power market does not necessarily mean that a state should not pursue restructuring. The outcome should be compared with the outcome that would be produced by existing regulation (Joskow 1997, 135). The inefficiencies of regulatory approaches are well documented in the economic literature.

Under regulation, firms are permitted to earn a fair rate of return on their capital invested. Prices are set during public rate hearings, at which firms document all costs involved in production, including fixed and variable costs. The actual return to capital is calculated after total costs are deducted from total revenue. In a regulated environment, firms supply all customers in their service area at a rate designed to cover their total costs (fixed and variable). This contrasts with a competitive market, where firms price at marginal cost, which, in the short run, is the variable cost of the most expensive unit supplying the market.

The establishment of a state-regulated monopoly presumes that one large firm is the most efficient way to supply the market. Economies of scale exist so that average

costs decline as firm size increases. As quantity supplied to the market increases, costs decrease and customers are able to purchase goods at a lower cost. This creates a downward sloping supply curve (S_R in figure 14); as quantity supplied to the market increases, price goes down because average costs go down.

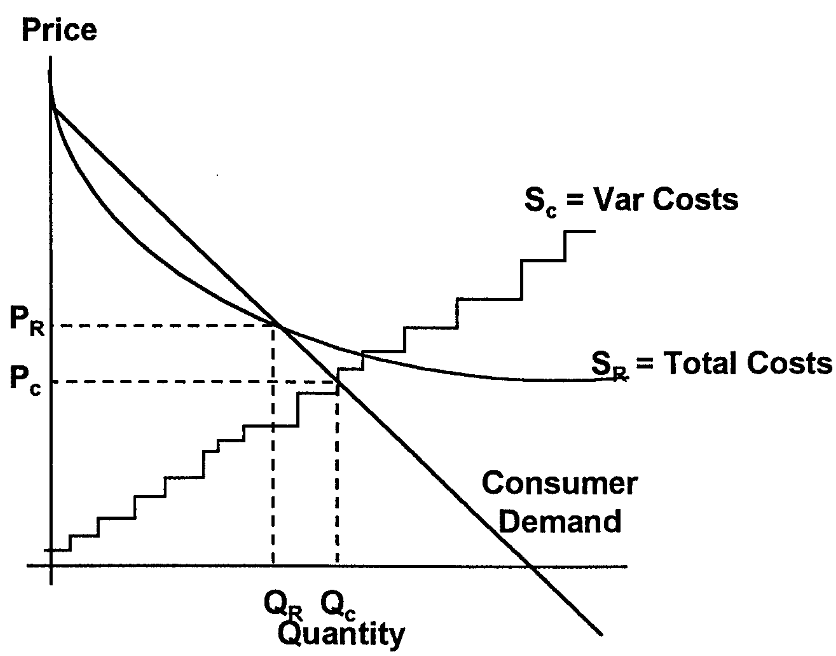


Figure 14. Pricing under regulation.

Pricing at average cost instead of at marginal cost, however, is inherently inefficient. At small quantities, fixed costs are averaged only a few units of output. As

quantity increases, fixed costs become a lower portion of total costs. So long as the supply curve slopes downward, average cost is always higher than marginal cost. As a result of pricing based on average total cost, prices under regulation are higher and quantity demanded is lower (P_R and Q_R vs. the competitive equilibrium, P_C and Q_C).

Other inefficiencies of regulated markets result in higher prices for consumers. The Averch-Johnson effect motivates utilities to favor an economically inefficient level of capital over labor (Averch and Johnson 1962, 1053). Cost-of-service regulation (COSR) limits utility profits to a fair return on the investments in capital assets. COSR encourages utilities to favor capital over other inputs in their production decisions. Firms overinvest in capital assets and depreciate them slowly. This is one reason why regulated utilities are required to get approval from their regulators before making new capital investments. Excess older, undepreciated generation also reduces the construction of newer, more efficient plants. One of the significant results of UK restructuring was the retirement of older, coal-fired generating stations and the construction of efficient, clean gas-fired plants (Newbery and Pollitt 1997, 1).

Leibenstien's "X-efficiency" is another problem faced by regulated monopolies. X-efficiency reflects a lax attitude on the part of regulated firms to minimize costs, because they are protected from competition by their monopoly franchise (Leibenstein 1962, 392). Earning a set rate of return provides limited incentives for technical innovation. Furthermore, once a firm completes a rate case with its governing PUC, it has limited incentives to reduce costs or increase revenue, unless it is operating under some form of performance-based regulation.

The existence of the Averch-Johnson effect and "X-efficiency" are empirical questions, but both concepts have some intuitive appeal. Just the threat of competition has caused utilities to implement many cost-cutting measures and become more efficient. Between 1986 and 1995, U.S. utilities reduced their workforce by 20%, laying off 100,000 workers (EIA 1996b, 86).

Therefore, policy makers may want to consider the inherent inefficiencies in each option when comparing regulation with restructuring. The mere existence of some degree of market power does not necessarily mean that a regulated solution is superior. Assuming that reliability of service is the same under both regimes, one possible

basis to compare these alternatives is expected market price. If market prices for each class of customer under restructuring are lower than prices that could be expected under regulation, then, all other things being equal, restructuring would have merit.

Chapter 3

THE COLORADO ELECTRICITY MARKET

The prospect of market power in a restructured environment, in effect creating an unregulated monopoly, is a significant concern in Colorado. As in many areas of the western United States, Colorado's population centers are widely separated. Much of the state's cheap electricity comes from plants located in remote areas where the cost of generation is low, near coal deposits or sources of hydroelectric electricity. Only a few transmission paths extend over long distances to bring this power to demand centers. This restricted transmission capacity, which already is frequently constrained, could limit entry by distant firms. The largest incumbent monopoly firm, Public Service Company of Colorado (PSCo), controls a dominant portion of the state's generation, transmission, and customers. These conditions may make it difficult to quickly create a competitive environment. The course restructuring takes in Colorado will be affected by a number of factors, including the current market participants, the

political and legal environment, transmission, consumer demand, and generation. These issues will be addressed in turn.

Current Market Participants

Electric utilities in Colorado include two investor-owned utilities (IOUs), twenty-six Rural Electric Cooperatives (RECs), twenty-nine municipal utilities, and three joint action agencies (figures 15 and 16). The smaller IOU, WestPlains Energy, serves 75,484 customers in Pueblo, Canon City, Rocky Ford and the surrounding areas, and operates or contracts for 245 megawatts (MW) of generation. PSCo is much larger, serving approximately a million electric customers in the Denver metro area, the San Luis Valley, Sterling, Greeley, and Grand Junction. Its annual revenue from electric sales is $1.27 billion. PSCo operates or controls through contracts 4,068 MW of generation (Colorado PUC 1996a, 7). Of 17 IOUs in the Western Interconnect, PSCo's average generation costs are the seventh lowest (RDI 1997, Table OV-1).

PSCo has recently completed a merger with Southwestern Public Service Company (SPS) of Amarillo, Texas, to form New Century Energies. SPS provides service to approximately

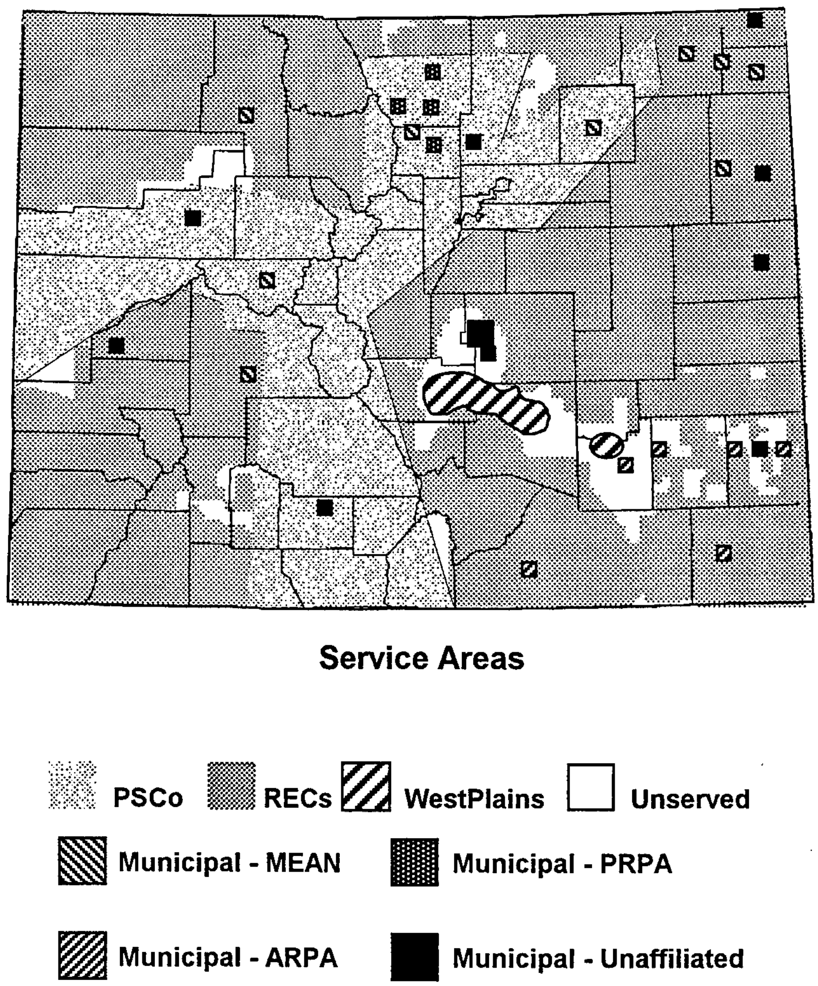
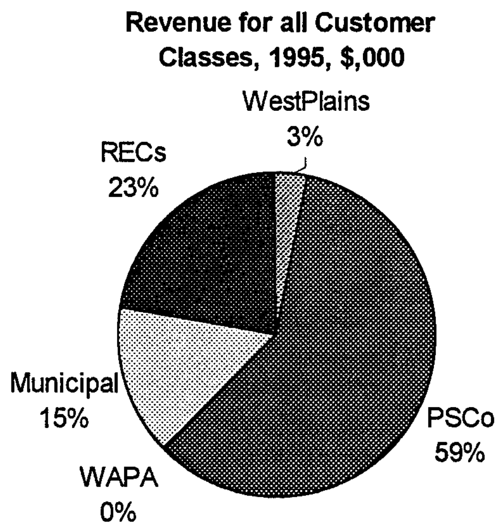


Figure 15. Colorado electric utilities.



Utility	Total Customers	Revenue $,000	Sales ,000 kWh	Avg Rev/kWh
WestPlains	75,484	74,951	1,305,084	5.74
PSCo	1,092,081	1,275,932	20,721,667	6.16
WAPA	7	1,394	80,186	1.74
Municipal	309,281	322,195	6,103,382	5.28
REC	362,889	487,522	7,106,500	6.86
State Total	1,839,742	2,161,994	35,316,819	6.12

Figure 16. Current electricity market participants.

Source: EIA 1996a, 165.

368,000 customers in Texas, New Mexico, Oklahoma, and Kansas. Because of its low generation costs SPS has been ranked among the companies best positioned for competition (RDI 1997, 19). Currently, the two companies are unable to share generation. However, they have proposed construction of a 400 MW transmission line to link PSCo and SPS. The advent of restructuring has caused a spate of mergers among electric utilities, as firms attempt to form strategic alliances and increase their competitiveness nation-wide. These mergers increase concentration within the industry, reducing the number of firms available to compete in a restructured environment, and potentially increasing the market power of those firms that remain. The PSCo-SPS merger can only increase the potential for the exercise of market power in generation in Colorado's restructured electricity market.

In other areas of the state, rural electrical cooperatives (RECs) serve as the local electric distribution utility. RECs service 23% of the overall demand, but geographically cover 75% of the state (Retail Wheeling Coalition 1997, 1). Their customers are widely spread over remote areas, which increase distribution costs. Eighteen of the Colorado distribution cooperatives purchase their

power through contracts from Tri-State Generation and Transmission Association (Tri-State).

Tri-State is collectively owned by its 34 member RECs, eighteen in Colorado, six in Nebraska, and ten in Wyoming (Tri-State 1997, 6). Tri-State owns 1,216 MW of generation. Most of this generation is committed to serve its member RECs. During 1996, total electricity demand from members ranged from 550 MW to 1,320 MW. Once Tri-State meets its member demand and other firm sales obligations, it can sell electricity from its excess capacity in the wholesale electricity market or, under restructuring, to retail customers. Tri-State has been ranked nationally among the top ten generation and transmission cooperatives best positioned for competition because of its low generation costs (RDI 1997, 23).

RECs also receive a portion of their generation from the Western Area Power Administration (WAPA). WAPA, a federal power agency, operates 10,581 MW of generation in the Western region. Most of this power is from low-cost, hydroelectric facilities. In 1995, WAPA's total sales were 32,910 GWh, 15% of total U.S. retail electricity sales (WAPA 1996, 6). By law, this power is primarily sold to RECs and municipal utilities under firm power contracts. WAPA also

sells some power to IOUs on the wholesale spot market. There are two major WAPA hydroelectric projects in the Rocky Mountain Power Area (RMPA), Loveland and Salt Lake. Loveland has 840 MW of hydroelectric generation in Colorado and Wyoming. The Salt Lake project includes generation in Arizona, Colorado, New Mexico, Utah, and Wyoming. Within the RMPA, the Salt Lake project includes 306 MW of generation in Western Colorado. Tri-State manages the distribution of its member RECs WAPA allocation.

The twenty-nine municipal power companies are, for the most part, small town operations that only distribute power. Most receive some allocation of power from the Western Area Power Administration. Others have banded together to create regional power authorities, including the Platte River Power Authority (PRPA), Arkansas River Power Authority (ARPA), and the Municipal Energy Agency of Nebraska (MEAN). A few other municipal companies purchase their power requirements in excess of their WAPA allocations from PSCo. Colorado Springs is unique among the municipal firms, operating as a vertically integrated municipal utility, with 542 MW of low-cost generation. Similar to municipal utilities are the three joint action agencies (JAAS). These are small,

municipally-owned firms that provide only generation and transmission.

The Political and Legal Environment

Article XXV of the Colorado state constitution invests the Public Utilities Commission (PUC) with power to regulate the state's electric utilities. However, some players in the Colorado electricity market are subject to limited or no PUC oversight, including independent power producers, the Western Area Power Administration (WAPA), and companies that self-generate electricity (Colorado PUC 1996b, I-2). By a 1983 act of the Colorado legislature, the RECs have been subject to PUC rate regulation on a voluntary basis. Only one REC, San Miguel Power Association, has chosen to remain under Colorado PUC jurisdiction. Tri-State's actions are subject to PUC review when they build new transmission or generation, and when they submit their integrated resource plans (IRPs). Municipal power utilities are not subject to Colorado PUC jurisdiction for power sales within their municipal boundaries. Nor are they subject to PUC jurisdiction if they charge the same rate for service beyond their municipal boundaries (Retail Wheeling Coalition 1997, 2). Furthermore, Article XXV emphasizes "home rule" for

municipalities. A town or city would have to give its consent if the state wanted to permit a utility to operate within the municipality's boundaries (State of Colorado 1997, 554). The effect of these restrictions is that, in reality, the Colorado PUC primarily regulates the two IOUs, PSCo, and WestPlains Energy.

The Colorado Association of Municipal Utilities and the Colorado Rural Electric Association, composed of the RECs and Tri-State, are members of the Retail Wheeling Coalition, along with the Colorado AFL-CIO, and several senior citizens organizations. In general, the Retail Wheeling Coalition opposes electric restructuring, or, in a more positive light, urges a "go slow" approach.

Municipal utilities and RECs fear that restructuring will let outside firms "cherry-pick" their most profitable customers. In their view, competition will only occur in their service areas for customers who have significant electricity demand. Municipal utilities and RECs are concerned that they would be unable to compete successfully if a larger company bid for the business of their large customers. These customers might desert their incumbent supplier, saddling the municipal utility or REC with residential and small commercial customers that are

expensive to serve. Problems could then "snowball" as rates for REC and municipal service increase for customers who do not switch to new suppliers. Those customers who do not switch initially then become dissatisfied because their rates increase and desert as well. While restructuring might not directly affect the revenues RECs earn as distribution utilities, it could adversely affect the generation revenues earned by Tri-State. Since the RECs collectively own Tri-State, they could also suffer financially.

Whether or not this "parade of horrors" is plausible is debatable. Since the distribution of electricity is expected to remain a regulated monopoly, RECs and small municipals who own no generation could also be viewed as indifferent regarding the actual supplier of electricity. There are no serious proposals being considered that would end their distribution monopoly. Therefore, the argument could be made that restructuring of generation would leave the RECs and municipals unaffected.

Municipal electric companies also provide payments in lieu of taxes to their local governments. The potential loss of these revenues is a major concern in these communities. Another concern of these municipal firms is

that, in some cases, their charters prohibit them from competing outside their service areas. In a restructured environment, these municipal utilities would only be able to lose market share, as outside firms steal their most profitable customers.

Municipal utility and REC concern over the loss of large customers may have some merit. Many of these firms rely on long-term contracts with power suppliers. According to one study, the rates specified in these contracts are well above rates that could be expected to prevail if electric restructuring of generation produced marginal cost pricing. Eighteen of the state's RECs have long-term contracts with Tri-State. Other RECs and municipals have long term contracts at potentially above market rates with PRPA, ARPA, and PSCo. Since restructuring will not necessarily abrogate these contracts, these firms could find themselves at a significant competitive disadvantage until the contracts expire, unless they can renegotiate them. If competition begins in 2000, this study has estimated that the total net present value of the above market cost of these contracts is above $498 million (table 2).

Table 2.

REC and Municipal Stranded Costs

Supplier	Company	GWh Purchased per year	% Firm Power Supplied	Purchase Price ($/MWh)	NPV of contract price over marginal generation cost ($000's)
ARPA	Lamar Utilities Board	88	98.2	33.52	3,904
ARPA	Trinidad Munic Power & Light	46	100.0	34.24	2,318
ARPA	La Junta Munic Utilities	60	99.1	35.44	2,158
ARPA	Springfield Munic Utilities	11	100.0	38.77	713
ARPA	Holly Light, Power & Water Dept	7	100.0	39.05	325
PRPA	Fort Collins Light & Power	989	100.0	34.79	42,397
PRPA	Longmont Electric Utility	509	100.0	34.90	21,619
PRPA	Loveland Water & Power	430	100.0	33.55	18,115
PRPA	Estes Park Light & Power Dept.	100	100.0	32.06	3,300
PSCo	Intermountain Rural Electric Assn	982	100.0	37.94	63,796
PSCo	Holy Cross Electric Assn, Inc.	811	50.7	55.62	38,502
PSCo	Yampa Valley Electric Assn, Inc.	407	100.0	38.30	30,437
PSCo	Grand Valley Rrl Pwr Line, Inc.	110	100.0	40.28	8,757
PSCo	Burlington Munic Light & Power	25	83.4	41.31	2,023
PSCo	Center Munic Electric	14	49.7	44.77	748
Tri-State	La Plata Electric Assn, Inc.	609	100.0	41.53	45,757
Tri-State	Poudre Valley Rea, Inc.	602	100.0	37.47	38,358
Tri-State	Delta-Montrose Electric Assn	425	100.0	43.12	34,676
Tri-State	United Power, Inc.	544	100.0	36.47	28,176
Tri-State	Mountain View Electric	375	100.0	40.40	26,986
Tri-State	San Isabel Elect Services, Inc.	279	100.0	40.67	19,744
Tri-State	Southeast Colorado Power Assn	144	100.0	43.86	11,587
Tri-State	Empire Electric Assn, Inc.	342	100.0	32.84	11,090
Tri-State	Mountain Parks Electric, Inc.	215	100.0	36.20	8,939
Tri-State	San Luis Valley R E C, Inc.	168	100.0	44.11	6,813
Tri-State	Gunnison County Electric Assn.	101	100.0	41.77	6,257
Tri-State	Sangre De Cristo Electric Assn.	70	100.0	43.80	6,185
Tri-State	San Miguel Power Assn, Inc.	125	100.0	42.89	6,141
Tri-State	White River Electric Assn, Inc.	95	100.0	40.46	5,743
Tri-State	Morgan County Rural Electric	172	100.0	39.56	5,593
Tri-State	K C Electric Assn	151	100.0	39.43	4,085
Tri-State	Y-W Electric Assn., Inc.	278	100.0	41.01	-293
Tri-State	Delta Municipal Light & Power	8	100.0	17.82	-443
Tri-State	Highline Electric Assn	289	100.0	42.00	-4,011

Source: RDI 1997, APP-12.

The current political climate suggests that if Colorado were to implement electric restructuring, participation by RECs and municipal power companies would be on a voluntary basis. The Retail Wheeling Coalition has the political clout necessary to defeat any restructuring measure that fails to meet the needs of its members. The Coalition's lack of support for restructuring may have contributed to the lukewarm response of the Colorado legislature to electric restructuring legislation during the 1996 and 1997 legislative sessions.

The most likely scenario for restructuring in Colorado, therefore, involves competition in generation within the service areas of the state's IOUs. RECs and municipal power companies could choose whether to participate. However, if an REC or municipal chose to compete outside its service area, it would have to reciprocate by letting other firms compete within its service area also. In 1997, Montana chose just this approach.

If Colorado implemented restructuring for only the IOUs, it would be pertinent to compare rates under restructuring to rates IOUs might offer under continued regulation. As part of the PUC's approval of PSCo's merger with SPS, a performance-based ratemaking plan was

implemented. The goal of this plan was to ensure the merger brought a positive benefit to PSCo's electricity customers. PSCo was granted the opportunity to earn an 11% return on equity. If the company earns in excess of 11%, part of the profits are returned to customers in the form of lower rates. As earnings increase beyond 11%, the company is also able to keep an increased share of the revenue (Colorado PUC 1996a, exhibit 1, 11). The intent of this plan is to provide a continuing incentive for PSCo to reduce costs.

Measured Return on Equity	Sharing Percentages	
	Ratepayers	PSCo
11%-12%	65%	35%
12%-14%	50%	50%
14%-15%	35%	65%
Over 15%	100%	0%

PSCo (1997, 19) forecasts that under performance-based rates, average system rates will decline to 4.79 cents/kWh by 2002, a 16% reduction, given the base scenario conditions. By the end of their forecast period in 2016, PSCo believes that rates will go down to 3.37 cents per kWh. PSCo forecasts electricity prices under a number of alternative scenarios. All scenarios predict similar reductions in electricity prices. These forecasts provide

some idea of how electricity prices might behave if Colorado continues the present regulatory system.

Existing Transmission

Inspection of the WSCC transmission network shows that, generally, power flows out of the RMPA, not into it (refer to figure 13, p. 37). Because of inexpensive hydroelectric generation and mine-mouth coal plants, the RMPA does not import a great deal of electricity. This simplifies an analysis of generation and demand, because the ability of firms beyond the boundaries of the RMPA to sell power in this region is limited.

During periods of low demand (off-peak), the RMPA functions as one market. The transmission network has the capacity to permit firms anywhere within the region to sell power to any customer. During periods of peak demand, the principal transmission paths within the RMPA can become constrained. There are thermal limits to the amount of power that can be transmitted over these lines. If a line's maximum capacity is exceeded, the line could overheat, sag into trees or onto the ground, and cause an outage. These transmission constraints tend to segregate the RMPA into three areas: (1) the Wyoming portion of the RMPA,

(2) Colorado west of the Continental Divide, and (3) Colorado east of the Continental Divide (figure 17).

The transmission paths in the RMPA are referred to as TOTs, referring to the TOTal flow on a specified grouping of transmission lines. TOTs have designated transfer capabilities based on rigorous engineering studies performed collectively by all utilities using these paths. The studies are conducted in accordance with guidelines established by the Western Systems Coordinating Council (WSCC), a division of the North American Electric Reliability Council (NERC). Once a transfer capability is determined along a TOT, transmission rights are allocated among the various firms that own transmission lines along the path.

TOT 1 defines the transfer capability between Colorado and Utah. TOT 2A defines the transfer capability between Colorado and New Mexico. TOT 3 defines the transfer capability from Wyoming into Colorado. Within Colorado, power flows from west to east across TOT 5, where the transmission paths cross the Continental Divide. TOT 7 rates the capacity of the transmission lines coming into the Denver metro area (table 3).

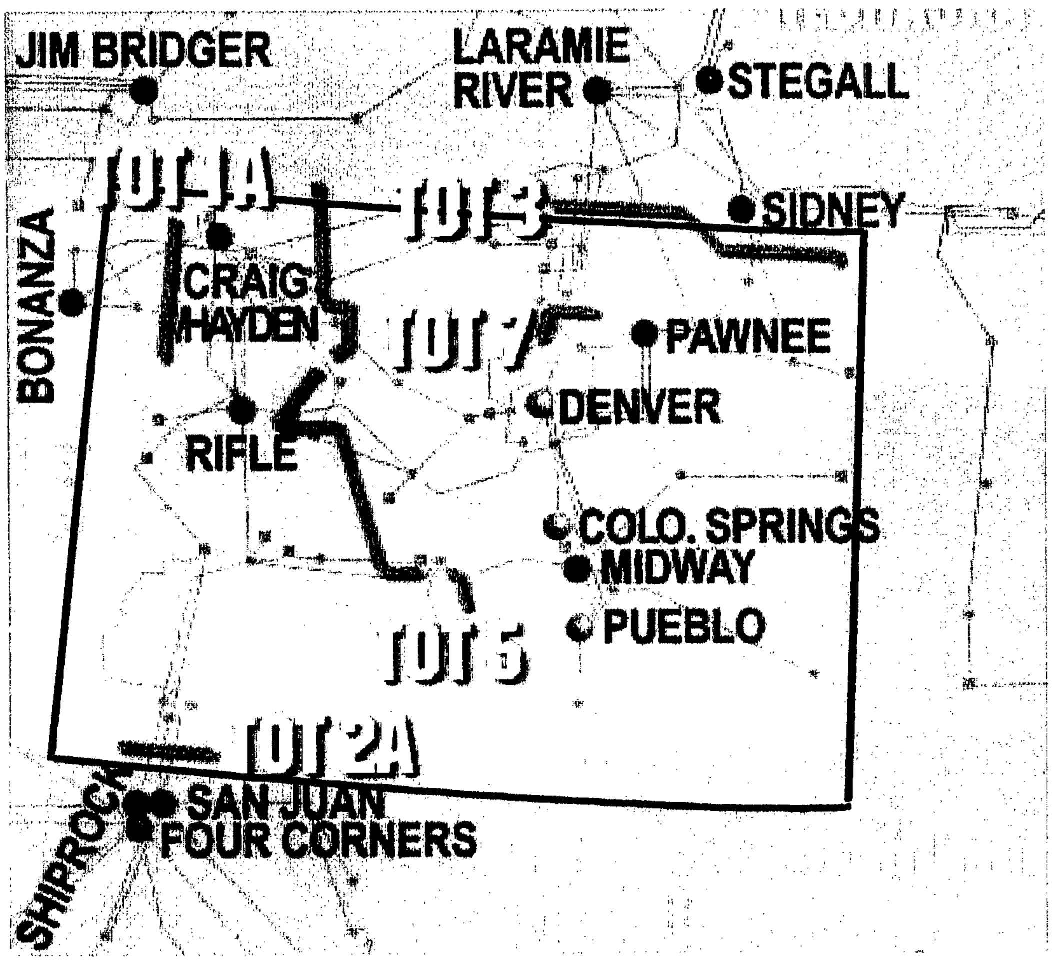


Figure 17. RMPA transmission constraints.

Source: RMPA OASIS site (www.rmao.com/OASIS).

Table 3.

Power Flows Within the RMPA

TOT	Location	Maximum Rating (MW)	Typical Rating (MW)	Ownership
1	NW Colorado	650 E - W	550	WAPA (60%), PRPA (6%), Tri-State (25%), UAMPS (9%).
2A	SW Colorado	690 N - S	650	WAPA (61%), PSCo(19.5%), Tri-State (19.5%).
3	Wyoming-Colorado	1424 N - S	1200	WAPA (25%), Missouri Basin Power Project (MBPP) (45%), PSCo (4%), Tri-State (26%).
5	W. Central Colorado	1680 W - E	Affected by TOT 3	WAPA (45%), PRPA (11%), Tri-State (15%), PSCo (29%).
7	N. Central Colorado	775 N - S	775	PSCo (58%), PRPA (42%).

Source: RMPA OASIS Internet site (www.rmao.com/oasis).

There are no alternating current (AC) transmission lines east from Colorado and Wyoming into Nebraska, because the AC power flow on the Eastern Interconnect is not synchronized with AC power flow on the Western Interconnect. There are two DC lines between the Eastern and Western Interconnections at Sidney and Stegall, Nebraska. However, these are not extensively used. In 1995, only 200 MWh were exported over these ties and 241 MWh were imported (RDI 1997, R-3).

There are interaction effects between TOTs 3 and 5. Whenever TOT 3 is loaded to its limit, TOT 5 becomes

constrained as well. Additional capability on TOT 5 cannot be used because it will overload TOT 3. Flow from TOT 3 also creates a phenomenon known as "loop flow" that reduces the transmission capability of TOT 5 by 200 MW. Other conditions may also limit the transfer capability of TOT 3 (table 4). Ordinarily, little power flows over the DC ties

Table 4.

TOT 3 Capacity Under Alternative Scenarios

Generator Conditions		DC Tie Status		
Laramie River MW	Pawnee MW	300 MW E - W	0 MW	300 MW W-E
1100	495	1424	1353	1143
550	495	1163	912	663
1100	0	1116	1141	1053
550	0	1106	950	716

Source: Colorado PUC 1994, Staff testimony on 1993 PSCo Integrated Resources Plan (January 12, 1994).

into Nebraska. If power is flowing over the DC ties, a west to east flow will lower the transmission capacity of TOT 3, while an east to west flow increases capability.

If production at the Laramie River Station, north of the constraint in Wyoming, is reduced for some reason, TOT 3's transmission capacity may drop anywhere between 10 MW and 480 MW. If the Pawnee generating station south of the

constraint in Colorado is not operating, TOT 3 transmission capacity may increase by up to 38 MW or drop up to 308 MW, under alternative scenarios. PSCo is currently upgrading portions of TOT 3. This work is expected to eliminate the reduction in capacity when the Pawnee station is off-line (PSCo 1997, 95).

In summary, transmission capability plays a key role in defining the generation market in the RMPA. At moderate or low levels of demand, the region functions as one market. At peak levels of demand, the RMPA may fragment into smaller markets. When maximum transmission capacity is reached on TOT 3, additional generation from Wyoming and Western Colorado cannot enter the market in eastern Colorado and the Front Range. Under these conditions, the market power of firms owning generation located in eastern Colorado could increase.

Customer Demand

Within Colorado, population is concentrated along the Front Range of the Rocky Mountains in the state's major population centers (figure 18). Population density appears to correspond closely to the concentration of electricity demand within the RMPA. With 73% of the region's demand in

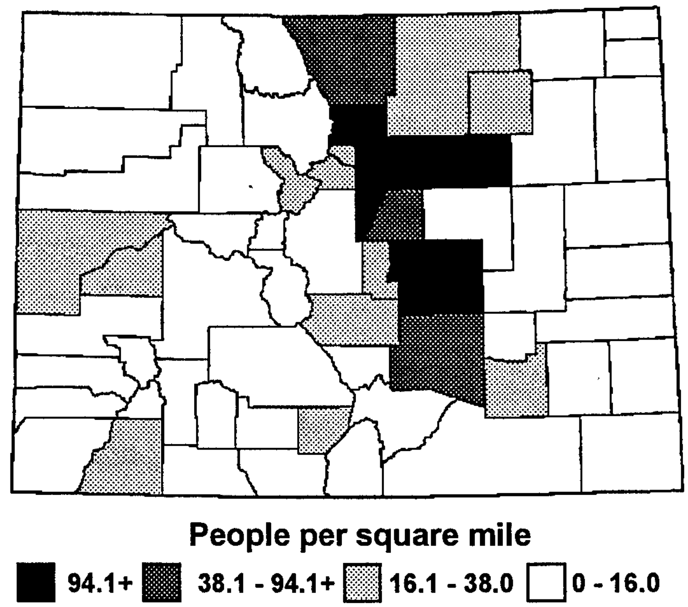


Figure 18. Colorado population per square mile.

Source: 1990 U.S. Census.

eastern Colorado, the Front Range would clearly be the principal market of interest for firms competing in a restructured electric market, as suggested by the numbers below (EIA 1996a, 165).

Region	Total 1995 Net Energy Sales (GWh)	% of RMPA Net Energy Sales	1995 Summer Peak Demand (MW)
Wyoming	8,105,181	18.7%	1,356
Western Colorado	3,680,552	8.5%	616
Eastern Colorado	31,636,267	72.9%	5,294
RMPA	43,422,000	100.0%	7,266

Unlike Montana and Wyoming, where industrial customers represent 46% and 59% of customer demand, demand in Colorado is evenly divided among customer classes (figure 19).

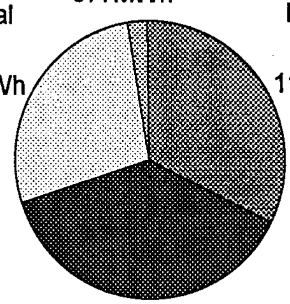


Figure 19. Colorado 1995 electricity demand by customer class.

Source: EIA 1996c, 35.

However, some large customers are able to negotiate preferential rates, even under the current regulatory framework. PSCo has negotiated, and the Colorado Public Utilities Commission has approved, lower rates for C F & I Steel in Pueblo, CO, as well as a few other large industrial customers.

Large commercial customers are also beginning to pressure incumbent monopoly firms to provide them with special rates. With electric restructuring opening the electric market in some states, national retail chains are demanding that incumbent monopoly firms in the remaining regulated states provide them with discounted rates now. Their threat is that unless these discounts are provided, they will not even consider purchasing generation from their present providers in a restructured environment, should Colorado choose to restructure.

The proliferation of special deals for large customers would seem to be one argument in favor of electric restructuring. Under the current regulatory framework, large commercial and industrial customers are beginning to use their market power to obtain rates unavailable to most other customers. Electric restructuring might at least give all customers the opportunity to negotiate their own deals.

Policy makers must also consider that demand is expected to grow over time. In order to meet forecasted demand and meet future reserve requirements, generation must be planned and constructed in a timely fashion. Market shares, and the ability to influence prices, can change as new generation is constructed to meet growing demand.

Restructuring plans must consider policies for the licensing and construction of new generation. The WSCC forecasts an annual load growth of 2% for the RMPA during from 1997 to 2006 (WSCC 1997b, 38). This would result in an increase of summer peak demands in the RMPA from 7,266 MW to 8,879 MW.

Restructuring could have both positive and negative effects on load growth. Under electric restructuring, consumers could be charged rates that vary over the course of the day. Under "real time pricing" consumers might resist paying a higher price of electricity during periods of peak demand. Consumers might choose to reduce consumption during peak periods. If this load is merely shifted to off-peak periods, for instance when a factory adjusts its work schedule to use electricity during off-peak periods, then annual total demand might continue to increase as forecasted, but peak demand could drop. Conversely, if prices under electric restructuring decrease, consumers may be inclined to consume more electricity, instead of less. The effect of restructuring on load growth is a significant source of uncertainty.

Generation

Within the RMPA, a few firms control the majority of generation capacity. PSCo owns 45% of RMPA generation. This control becomes even more pronounced when transmission is constrained within the RMPA. In eastern Colorado and the Front Range, PSCo owns or controls 75% of generation. Control of such a large share of generation could give PSCo the ability to set market prices in excess of marginal cost in a restructured market.

Of the 9,077 MW of generation in the RMPA, a total of 5,279 MW is affected by power contracts between utilities. These contracts must be considered when analyzing the market shares of each firm. Over the life of the contract, the selling company must provide firm, or contingent firm, power to the buyer. Comparing the prices of some of the contracts, it is clear that some companies got better deals than others. However, in defense of people who committed their companies to contracts that appear to be extremely expensive now, these prices may have seemed fair at the time the deals were negotiated. With the prospect of restructuring, firms are becoming more cost conscious when signing power contracts, and some contracts are being renegotiated.

Another consideration in an analysis of generation is the location of each station or plant. Analysis of transmission constraints shows the possibility that transmission constraints under periods of peak demand could segment the RMPA into three regional markets. Once transmission paths are constrained, location of generation becomes critical. Additional inexpensive generation in Wyoming is of little benefit to eastern Colorado customers if transmission capacity is not sufficient to deliver that electricity.

In the same way, additional transmission capacity is of little value if generation is not available on the grid. An RDI study forecasts that generation reserve margins across the Western Interconnect are declining markedly as demand increases over time (table 5). This suggests that the ability of firms to enter distant markets will decline as reserve margins erode.

Generation within the RMPA, as well as by sub-region is shown (tables 6-9). These tables depict the generation market shares for each company. Generation supply curves, reflecting the marginal cost, and contract cost and capacity have also been plotted for the RMPA and each region (figures 20-23). These curves plot the marginal cost of each plant.

Table 5.

Selected Reserve Margins in the WSCC

	Low load growth		Base case growth		High load growth	
	With planned additions	Without	With planned additions	Without	With planned additions	Without
Arizona and New Mexico						
1996	19.42%	19.38%	19.42%	19.37%	19.42%	19.38%
2000	12.36%	11.60%	13.91%	13.13%	8.05%	7.32%
2005	5.76%	2.58%	2.77%	-0.32%	3.16%	-6.07%
Northwest Power Pool (WA, OR, ID, MT, UT)						
1996	14.25%	14.07%	14.25%	14.07%	14.25%	14.07%
2000	13.71%	8.39%	11.25%	6.04%	9.32%	4.20%
2005	9.40%	0.78%	4.41%	-3.81%	.12%	-7.76%
RMPA						
1996	32.24%	32.24%	32.24%	32.24%	32.24%	32.24%
2000	33.34%	24.28%	30.98%	22.09%	28.21%	17.43%
2005	35.33%	16.44%	30.12%	11.96%	23.90%	6.60%

Source: RDI 1997, Table R-1a.

A complete table of generation at the plant level is in appendix A. Generation contracts are appendix B. This data is compiled from company annual financial reports, and IRPs submitted to the Colorado PUC.

Summary of the Colorado Electricity Market

From the preceding information, it is apparent that the potential for market power is greatest in eastern Colorado. Within this region, peak demand (5,294 MW) exceeds the capacity of eastern Colorado generation (4,728 MW). PSCo owns 75% of the native generation. Transmission is

Table 6.

RMPA Generation Market Shares

Company	MW	% Share
ARPA	31	0.3
Basin Electric	651	7.2
Black Hills	220	2.4
CO Springs	542	6.0
LAC	10	0.1
MEAN	22	0.2
Pacificorp	243	2.7
PRPA	409	4.5
PSCo	4,068	44.8
Salt River Project	379	4.2
Tri-State	1,216	13.4
WAPA-Loveland	860	9.5
WAPA-Salt Lake	321	3.5
WestPlains Energy	82	0.9
WMPA	23	0.3
Total generation	9,077	
Peak summer demand	7,266	

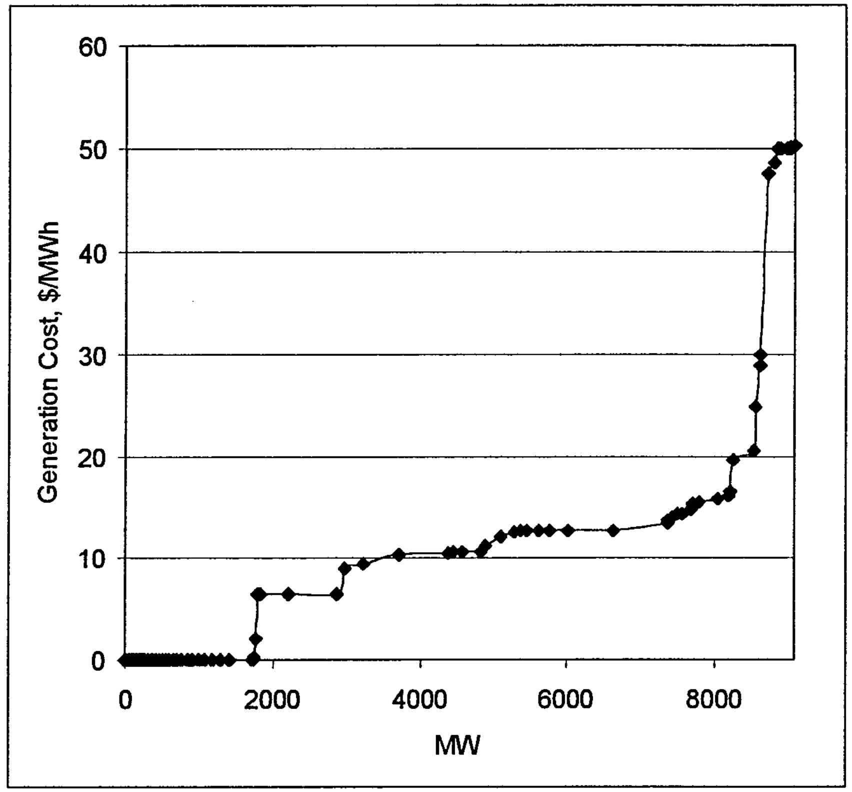


Figure 20. RMPA generation supply curve.

Table 7.

Eastern Colorado Generation Market Shares

Company	MW	% Share
ARPA	31	0.7
CO Springs	542	11.5
PRPA	255	5.4
PSCo	3,518	74.4
Tri-State	100	2.1
WAPA-Loveland	200	4.2
WestPlains Energy	82	1.7
Total generation	4,728	
Peak summer demand	5,294	

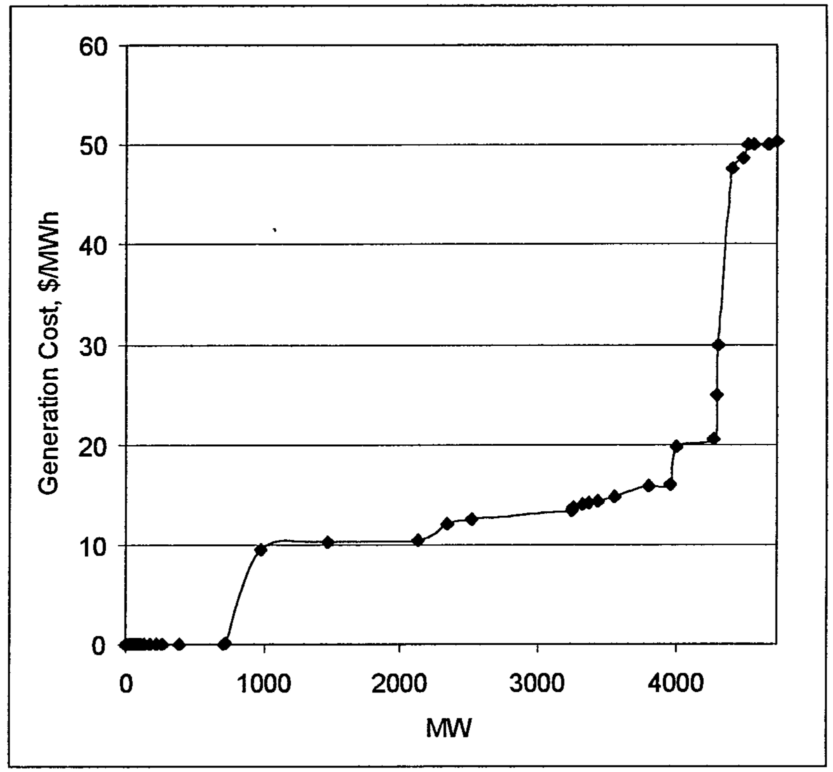


Figure 21. Eastern Colorado generation supply curve.

Table 8.

Western Colorado Generation Market Shares

Company	MW	% Share
MEAN	4	0.2
Pacificorp	243	9.3
PRPA	154	5.9
PSCo	550	21.0
Salt River Project	379	14.4
Tri-State	718	27.4
WAPA-Loveland	232	8.8
WAPA-Salt Lake	321	12.2
WMPA	23	0.9
Total generation	2,624	
Peak summer demand	616	

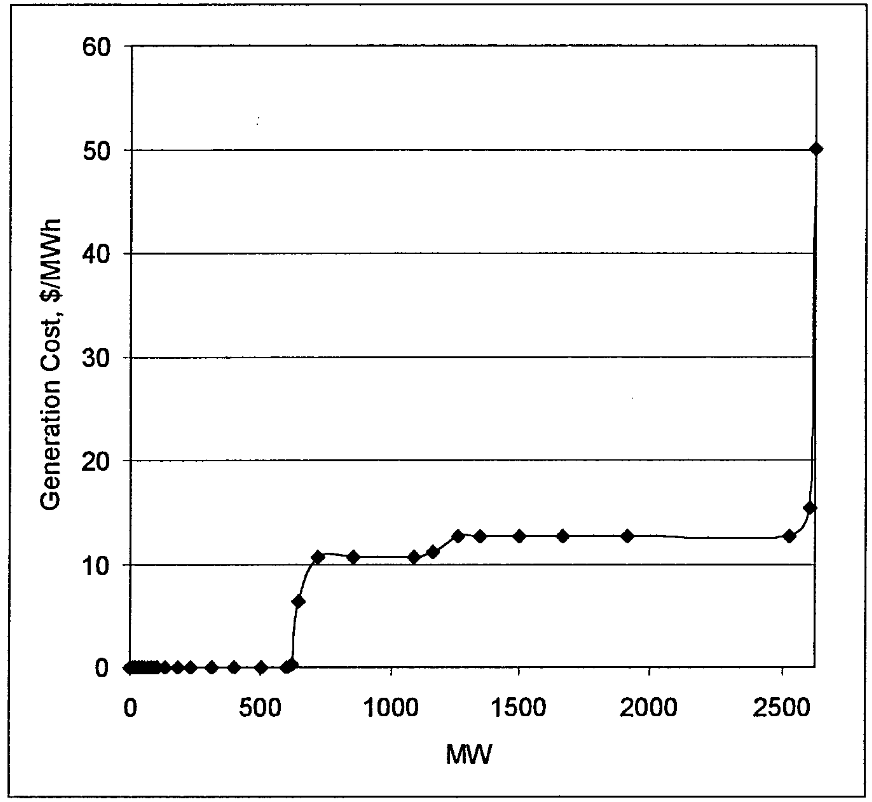


Figure 22. Western Colorado generation supply curve.

Table 9.

Wyoming Generation Market Shares

Company	MW	% Share
Basin Electric	651	37.7
Black Hills	220	12.8
LAC	10	0.6
MEAN	18	1.0
Tri-State	398	23.1
WAPA-Loveland	428	24.8
Total generation	1,724	
Summer peak demand	1,356	

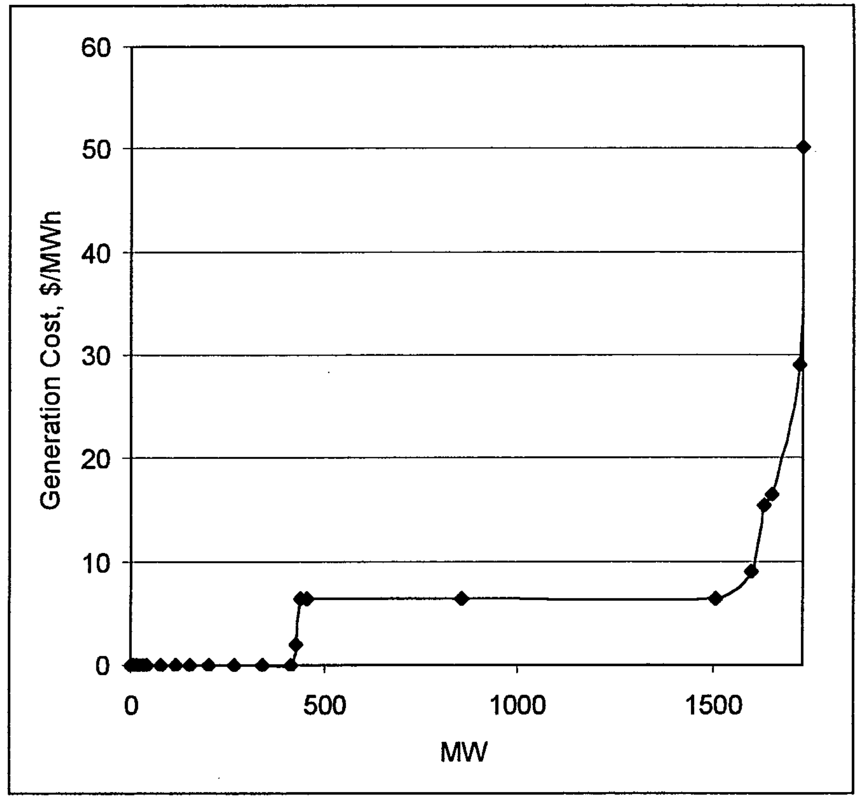


Figure 23. Wyoming generation supply curve.

constrained to other regions, where PSCo also owns significant generation.

In contrast, generation capacity exceeds demand in the western Colorado and Wyoming portions of the RMPA. Furthermore, these regions connect to the rest of the Western Interconnect. While historical power flows, for the most part, are exports from the RMPA, the transmission network would permit imports as well. If a firm in western Colorado or Wyoming attempted to increase prices over marginal cost, it could expect entry from a firm in a neighboring region.

Therefore, a restructured electricity market for eastern Colorado could be modeled as monopolistic competition with PSCo acting as a dominant firm. During periods of low to moderate demand, the market would be competitive, with prices reflecting the marginal cost of generation. At higher levels of demand, transmission constraints and PSCo's large eastern Colorado market share might create the possibility that PSCo could exercise monopoly power, increasing prices above marginal cost.

Chapter 4

LITERATURE REVIEW

The prospect of electric restructuring has prompted an outpouring of articles and studies representing a number of perspectives: economists, regulators, engineers, and pundits. Many publications represent the views of particular stakeholders in the restructuring debate, and must be viewed with some skepticism. Several academic centers have devoted substantial research to electric restructuring, including the Harvard Electricity Policy Group, the Oak Ridge National Laboratory, and the University of California Energy Institute. State and federal government perspectives are reflected in publications of the National Regulatory Research Institute (NRRI), an agency of the National Association of Regulatory Utility Commissioners (NARUC), and the U.S. Department of Energy's Energy Information Administration (EIA). The Electric Power Research Institute (EPRI) and Edison Electric Institute (EEI), representing the electric utility industry perspective, have also published extensively.

This literature review on the potential for market power in restructured electricity markets is chronological, representing the major topics that have been discussed in the academic literature as the move to restructure electricity has progressed. This review begins with one of the most widely referenced early analyses, and continues through to recent publications. Much of the early literature concerns electric restructuring in the UK, where a government-owned, vertically integrated electric monopoly was privatized and restructured. Initially, these papers debated how restructured markets might develop in the UK after generation was deregulated. Once this was complete, empirical studies of the effects of market power in the UK generation market followed. More recently, the focus of much of the literature has shifted to California, and how to appropriately structure a competitive market for generation there.

This review will concentrate on the conceptual framework, methodology, and remedies for market power in generation presented in the these studies. This approach should provide some insight as to how to appropriately analyze a restructured generation market in Colorado. However, there also may be fundamental differences between

Colorado's generation market and the UK or California. State policy makers can learn from these earlier examples in designing a proposal for Colorado's electric restructuring, but might do well to bear in mind Colorado's differences also.

The electric monopoly in the UK was broken up into three large firms. Similarly, California has three large IOUs that will all compete for business in its restructured market. Consequently, much of the literature uses a Cournot model, which will be described later, to analyze market power.

In contrast, Colorado, like a number of other states now contemplating restructuring, has one electrical utility that owns a large share of the state's generation. In states where one firm owns a dominant share of the generation, market power would seem to be a greater concern. The Cournot model, which was the market paradigm for the UK and California, would not be appropriate. Therefore, while earlier studies may provide insights, states with a dominant firm may have to develop different approaches.

Early Analyses

One of the earliest studies focusing on market power in electric generation, was Schmalensee and Golub's (1984) analysis of deregulated wholesale electricity markets. They use a very general model to estimate equilibria for 170 electricity markets in the United States. Then, they calculate two indices of market power for each market, the Herfindahl-Hirschman Index (HHI), and the Lerner Index.

The HHI is the sum of the squared market shares for each firm within the market.

$$HHI = \sum_{i=1}^{n} (market\ share_i)^2 \text{ where i = firms 1,...,n} \qquad (4.1)$$

In a market with 100 firms, where each firm has 1% of the market, HHI = $\sum_{i=1}^{100} (1)^2 = 100$ In contrast, a monopoly market with one firm would have an HHI = $100^2 = 10{,}000$. A moderately competitive market with five equally sized firms would have an HHI = $\sum_{i=1}^{5} 20^2 = 2{,}000$. While the HHI is not a direct measure of a firm's ability to exercise market power, markets with a high HHI are more likely to experience problems with market power.

The second measure Schmalensee and Golub use is a variation of the Lerner index, using quantity instead of price, where Q^c = competitive quantity and Q^e = equilibrium quantity.

$$QI = \frac{(Q^c - Q^e)}{Q^e} \tag{4.2}$$

A firm's market power is reflected in its ability to restrict output from the competitive equilibrium, which consequently drives up price.

Schmalensee and Golub define an analytical framework that forms the basis for a number of subsequent studies of market power in generation markets. In Schmalensee and Golub's analysis, firms initially make a decision on the quantity they will supply to the market. This decision is reflected in the portfolio of generation plants they own. In restructured electricity markets with a few large firms, competition takes place on the basis of quantity. Market price is determined from the interaction of consumer demand and the quantity supplied to the market. This type of oligopolistic competition produces a Cournot equilibrium.

In the Cournot model with two firms (i and j), firm i maximizes profits ($\pi(q)$, profits as a function of quantity

supplied to the market), subject to the inverse market demand function ($p(q_i+q_j)$, price as a function of total quantity supplied to the market), and the firm's own costs ($c_i(q_i)$, cost as a function of quantity).

$$\max \pi_i(q) = q_i \bullet p(q_i + q_j) - c_i(q_i) \tag{4.3}$$

The first order conditions are symmetric for firms i and j when they have the same costs ($q_i = q_j$).

$$p(q_i + q_j) + q_i \bullet p'(q_i + q_j) - c_i'(q_i) = 0 \tag{4.4}$$

Solving this system of equations simultaneously for both firms produces equilibrium market price and the quantities produced by each firm. Using the Lerner index, market quantity and price under Cournot competition can be compared to a competitive equilibrium, where price equals marginal cost, to determine the extent of market power.

At equilibrium in this type of analysis, each firm has low cost plants operating at full capacity, high cost plants that are idle, and one marginal plant operating at some level up to its maximum capacity. A Cournot equilibrium price will be lower than a monopolist's price, but higher than the competitive equilibrium. As the number of firms in the market increases, competition increases and market price and quantity approach the competitive equilibrium.

Schmalensee and Golub's model also incorporates the effects of transmission fees and losses. The cost of generation at plant i includes an amount (w_i) that reflects the fee that must be paid to transmission owners per unit of output. Additionally, some fraction of the plant's output (r_i) dissipates as a function of distance traveled in the transmission system according to Kirchoff's laws. Transmission losses have the effect of reducing an electric plant's total capacity (K_i) when it enters a distant market. Plant i's cost (c'_i) and capacity (K'_i), adjusted for transmission losses are shown (Schmalensee and Golub, 15).

$$c'_i = w_i + \frac{c_i}{1 - r_i} \tag{4.5}$$

$$K'_i = K_i \bullet (1 - r_i) \tag{4.6}$$

While Schmalensee and Golub's analysis forms the basis for many subsequent studies, it is also criticized for its reliance on the HHI as a measure of market power. Later studies point out that market shares that existed in a regulated environment may change greatly under restructuring. Furthermore, the dimensions of an electricity market change considerably as a function of transmission constraints. The existence of transmission constraints isolates markets. Once these constraints are

relaxed, firms over a wide area may compete, limited only by their increased costs due to transmission charges and power losses. Thus, the HHI is a static measure in a very dynamic market.

Furthermore, the HHI measures only one of aspect of market power. The ability of firms to charge prices in excess of marginal cost (MC) is also related to the elasticity of customer demand (ε). In a market with n identical firms, it can be shown that the percent markup of price over marginal cost is

$$\frac{P - MC}{P} = \frac{1}{n \bullet \varepsilon} = \frac{(.001 \bullet HHI)}{\varepsilon} \tag{4-7}$$

This equation highlights the fact that price responsive demand plays an important role in an analysis of market power (Borenstein, Bushnell, Kahn, and Stoft 1996, 11). In a market with a demand elasticity of $|0.2|$ and 10 equally sized firms, this equation indicates that market price would be twice marginal cost. In contrast, as demand elasticity approaches $|1.0|$, firms realize little additional profit if they increase price.

Despite these criticisms, the HHI remains an important measure of market power, because of its use by the U.S.

Department of Justice in antitrust litigation (Werden 1996, 20). When the HHI is less than 2,500, the market is considered at low risk to the exercise of market power. In his testimony before the Federal Energy Regulatory Commission (FERC), Joskow (1995) recommends that FERC define the relevant markets, identify suppliers and their associated capacity, and then use measures such as the HHI as a screen for market power. If the HHI for a market is below some threshold level, such as 2,500, the market would be presumed to be competitive. Persuasive evidence of market power abuse would be required to merit further investigation once a market met this standard (Joskow 1995, 29).

Building on Schmalensee and Golub's study, Klemperer and Meyer (1989) develop the theory of supply function equilibria. Supply function equilibria extend the Cournot model to incorporate a firm's uncertainty as to the quantity that its rivals will produce. Supply function equilibria are particularly well suited to restructured electricity markets with spot markets for generation. In an electricity spot market, generation firms bid a supply curve that identifies the price-quantity combinations at which they are willing to produce electricity, usually a day in advance.

The market auctioneer compares the bids and identifies which firms will supply generation at each level of demand.

Instead of bidding a specific equilibrium quantity, as in the Cournot model, firms must calculate their optimal supply function. Firms bid without precise knowledge of consumer demand or the behavior of their rivals. This element of uncertainty results in prices that are below the Cournot equilibrium, but still above a competitive equilibrium. Instead of simultaneously solving first order conditions for price and quantity, supply function equilibria require the simultaneous solution of a system of differential equations to determine each firm's optimal supply function. A number of subsequent papers, including Bolle, von der Fehr and Harbord, and Newbery incorporate the use of supply function equilibria into Cournot models of market behavior.

Bolle (1992, 102) advances Klemperer and Meyer's approach by adding the complication that the spot market will be a repeated game. Over time, firms may adopt a variety of strategies to earn economic profits, even if the number of firms in the market increases. Firms could engage in tacit collusion to keep price above marginal cost. For these reasons, Bolle expressed concern that the proposed (at

that time) British spot market for generation might not produce lower prices. In his opinion, continued regulation might be required to prevent the exercise of market power. This prediction proved to be particularly prescient.

Empirical Studies of the UK's Restructured Market

Von der Fehr and Harbord (1993) develop an auction model of the British spot market for electricity. Their model suggests that during periods of low demand, when excess generation is available, firms will price at marginal cost. If any firm attempts to increase price, other firms have excess capacity and will bid additional generation at marginal cost. However, as demand increases, firms that control generation at the margin may have the ability to withhold capacity from their supply bids. These firms can increase price above marginal cost.

Furthermore, the supply functions bid in a generation market are step functions. As demand fluctuates, there may be distinct jumps in price as additional generation enters and exits the market. Price volatility would be endemic to restructured electric markets, as demand varies daily and seasonally, requiring different generation sets to meet demand. Von der Fehr and Harbord then display actual bids

from the two largest firms in the British spot market as examples of the way firms may exercise market power (figure 24).

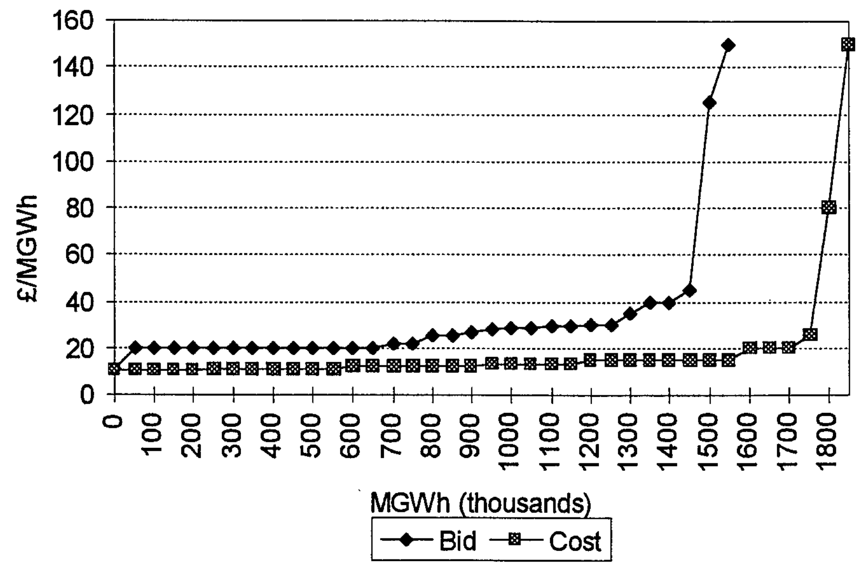


Figure 24. PowerGen bids vs. costs, February 22, 1991.

Source: Von der Fehr and Harbord 1993, 542.

In this example, PowerGen is bidding at prices close to its marginal cost of generation over most levels of demand. However, at high levels of demand, the difference between price and marginal cost increases. PowerGen simply doesn't bid all of its available generation. It is withholding capacity in the "flat" portion of its supply curve. This

strategy causes price at high levels of demand to differ significantly from marginal cost. Since the marginal unit of generation sets market price, this strategy earns a higher profit for all of the firm's low cost generation when demand is high. Von der Fehr and Harbord then show that PowerGen and its chief rival, National Power, strategically adjusted the quantity of generation they bid each day. These firms ensured peak demand intersected the supply curve where it was "steep" during a portion of each day to maximize their profits.

David M. Newbery, a professor in Applied Economics at the University of Cambridge has been an active participant in the conception and development of electric restructuring in the UK. Green and Newbery (1992, 930) point out that the initial economic model for the UK electricity market assumed a Bertrand equilibrium would prevail. A Bertrand equilibrium assumes that if any firm sets price above marginal cost, other firms producing at marginal cost have enough capacity to supply all of the customers of the firm attempting to exercise market power. Bertrand competition produces a market that is fiercely competitive. This economic efficiency results in a socially optimal equilibrium; producer surplus and consumer surplus are both

maximized. Furthermore, Green and Newbery show how the advent of high efficiency, low-cost combined-cycle gas turbines facilitates market entry. The low capital costs and short construction time of these generators creates a threat of entry that would discipline the market if any firm attempted to exercise market power.

However, Green and Newbery's analysis also predicts that the presence of transmission constraints creates opportunities for the two largest firms in the restructured UK electricity market to exercise market power in generation when demand is high. When the UK restructured its electricity market, the national electricity monopoly was divided into three firms. The nation's coal-fired generating stations were given equally to PowerGen and National Power. Nuclear Electric remained a government agency, controlling all of the UK's nuclear plants.

Using Klemperer and Meyer's supply function equilibria, Green and Newbery show that the restructured electricity market could result in periods of extremely high prices in the short run, that is, until entry by new firms occurs. This happens because PowerGen and National Power both control substantial portions of electric generation. When demand is high, Bertrand competition cannot exist. Either

firm can set higher prices for its marginal units knowing that no other firm in the market has enough capacity to force prices back to marginal cost. Green and Newbery then go on to show that if the government had divided the former state monopoly into five equally sized firms, effective competition might occur at all levels of demand.

In a later article, Newbery (1995, 39) displays data from the UK spot market to show that PowerGen and National Power set the spot price for electricity 90% of the time, while controlling only 60% of the generation. From the implementation of restructuring in 1990 to the end of 1995, 15.3 GW of old generation had been retired or downrated in capacity, primarily by National Power and PowerGen. This was replaced by new 8.1 GW of new CCGT generators built by small firms (Newbery 1995, 53). The two dominant firms retired generation at a rate faster than entry by new firms to maintain market power. If PowerGen and National Power continue this policy over the long run, it would seem likely that their market share will eventually erode to the point that they no longer have market power. To date, this has not occurred (Newbery and Pollitt 1997, 1).

Newbery observes that long-term contracts for power tend to produce pricing at marginal cost (Newbery 1995, 39).

Firms negotiating long-term contracts consider not only the present generation firms in the market, but also the potential effect of entry by new firms. Thus, long-term contracts are able to take advantage of a market's contestability, even when the current market is not competitive.

In 1997, Newbery co-authored "The Restructuring of the CEGB, Was it Worth It," which summarizes the net effects of restructuring in the UK. This article concludes that competition in generation produced substantial benefits. Labor productivity in the UK electric industry doubled. Generation costs dropped in real terms by 50%. The switch from coal-fired generating stations to gas turbines caused a substantial drop in emissions of sulfur dioxide and nitrogen dioxide, significantly reducing acid rain. The switch to gas generation, however, resulted in the collapse of the British coal industry. Before restructuring, coal mines employed approximately 250,000 workers. Within five years of restructuring, coal employment dropped to 7,000 (Newbery and Pollitt 1997, 2). Lower generation costs brought higher stock prices and profits to electric utilities, but consumer electricity prices were unchanged in real terms. From a consumer perspective, Newbery's assessment is that the

British government missed an opportunity initially by failing to sufficiently divest the incumbent monopoly of its generation assets (Green and Newbery 1992, 953).

California's Restructured Electricity Market

With California becoming the first U.S. state to implement electric restructuring for all customers in 1998, a number of recent studies have focused on the potential effects of market power in generation there. In particular, the University of California Energy Institute has published extensively, with research financed by the California Energy Commission and the U.S. Department of Energy.

In "Market Power in California Electricity Markets," Borenstein, Bushnell, Kahn, and Stoft (1996) identify the long-term consequences of a firm's attempt to exercise market power in generation. By charging prices above marginal cost, firms stimulate entry into the market. Price gouging may ultimately cause a firm to lose its competitive advantage as new, low-cost producers enter the market.

Higher prices also encourage customers to devote more energy to finding substitutes. The price elasticity of demand plays a key role in mitigating market power (as equation 4-7 demonstrates). The demand for electricity is

generally viewed to be price inelastic. Without identifying potential solutions, Borenstein, et al stress that policy makers implementing competition in generation can do much to mitigate market power by improving the price responsiveness of demand.

In "The Competitive Effects of Transmission Capacity," Borenstein, Bushnell, and Stoft (1997) develop the idea that adequate transmission capacity plays a key role in making markets contestable. The transmission network provides the capability for Bertrand competition to take place as originally envisioned in the UK's restructured market. The threat of entry by a distant firm at a lower price disciplines producers from increasing prices above marginal cost. Even if a transmission path is unused, its mere existence creates the threat of entry. They demonstrate that when transmission capacity exceeds peak market demand, firms will be required to price at marginal cost (Borenstein, Bushnell, and Stoft 1997, 14). Of course this presumes the existence of excess generation in sufficient quantity to take advantage of that transmission capacity.

The authors contrast the unique role of transmission in restructured electricity markets with the "used and useful" role of assets in a regulatory environment. Under

regulation, firms are required to demonstrate the usefulness of new investment to state PUCs. This policy is designed to keep firms from making unnecessary investments in capital assets to increase their profits (the Averch-Johnson effect). Under restructuring, the authors note (page 24) that transmission could play a significant role in market behavior, whether or not it is used.

Simulation Models

Using Cournot and supply function equilibria to model restructuring highlights the economic incentives of firms with market power to manipulate prices. However, these models do not have great fidelity to the engineering constraints that play a significant role in electric markets. For instance, Schmalensee and Golub's assertion that a restructured generation market produces a set of low-cost fully loaded plants, a set of high-cost idle plants, and at least one marginal plant is not entirely correct.

Some generation is best suited to run at a relatively constant rate. Coal-fired generating stations are one example of baseload generation. Attempting to follow the variation in demand with these plants would cause them to operate inefficiently and decrease their reliability. Other

generation, such as hydroelectric plants, follows load easily. However, hydroelectric plants are limited by environmental constraints. Their reservoirs can hold only a certain amount of water. Hydroelectric plants may also be limited in the amount of water they can release in a given time. Increased water flow could cause environmental damage downstream. Therefore, even though hydroelectric power is normally the cheapest source of generation, it is not necessarily the first generation brought on line.

Generally, these engineering constraints are captured in great detail in simulation models. Simulation models are particularly well suited to portray an interconnected transmission grid, with local variations in demand and generation. Simulation models identify when transmission paths become congested, forecast the need for new generation, and provide insights into the dispatch of generation (Kahn, Bailey, and Pando 1996, 6). However, simulation models dispatch generation on the basis of marginal cost. These models were initially developed for a regulated environment. Their goal is to estimate the least-cost means of providing electricity to the market. In this respect, market power analyses have generally not employed simulation models.

Nevertheless, some analysts have applied marginal cost models to estimate the market price for generation in restructured electricity markets. The EIA's publication "Electricity Prices in a Competitive Environment" (1997) is an example of a study that uses simulation to calculate price at marginal cost. However, since these studies ignore market power effects, they may overstate the benefits of electric restructuring.

A recent paper by Borenstein and Bushnell (1997), "An Empirical Analysis of the California Electricity Market," uses the Cournot model in a simulation to capture the strategic behavior of firms, while incorporating a number of engineering constraints particular to electric markets. In this analysis, transmission constraints create four regional markets, two within California, north and south, and two external markets, the Northwest Power Pool (Oregon, Washington, Idaho, Utah, and Montana), and the Southwest region (Arizona and New Mexico). To account for transmission effects, out-of-state generation capacity is reduced and costs are increased in a manner similar to the one proposed by Schmalensee and Golub.

Out-of-state firms are assumed to act as price takers. The logic of this assumption is that if any out-of-

state firm attempted in increase its price, sufficient out-of-state capacity exists so that price taking firms would undercut the price of the firm attempting to exercise market power. Out-of-state fringe firms compete in the California market at the quantity of their excess capacity, reduced according to transmission loss factors, up to the level permitted by transmission constraints.

Within California, small IOUs and municipal utilities also act as price takers. In-state generators from small firms compete at their total generation capacity. Together, out-of-state producers and small in-state producers constitute the competitive fringe.

In a restructured California electricity market, the study contends three firms are large enough to exercise market power: Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric. These firms will compete over the market's residual demand function, $D_r(P$. Residual demand is the quantity of market demand above the supply capacity of the competitive fringe.

$$D_r(P) = D(P) - S^f_{CA}(P) - \sum Min\,(S^f_{\text{out of state}}(P)\,,\,TR_{\text{out of state}}) \qquad (4.8)$$

where $D(P)$ is the original demand function, $S^f_{\text{out of state}}$ represents the out-of-state fringe, S^f_{CA} represents the in-

state fringe, and $TR_{\text{out of state}}$ represents transmission capacity (Borenstein and Bushnell 1997, 11). Each Cournot firm maximizes its profits over this residual demand curve, taking into account the quantity the other Cournot firms will supply (as shown in equation 4.3).

Borenstein and Bushnell's simulation (1997, 14) attempts to capture the unique constraints relevant to hydroelectric power by allocating this capacity to peak demand periods. They call this technique "peak shaving" because it equalizes non-hydroelectric production across demand periods. Baseload generation is then able to run at a constant rate. This method approximates the actual employment of hydroelectric assets.

The study uses a range of demand elasticities from $|0.1|$ to $|1.0|$. To represent reserve requirements, Borenstein and Bushnell simply increase demand by 7%, which approximates Western Systems Coordinating Council (WSCC) reserve requirements. Using the all of these assumptions, the study solves the Cournot system of simultaneous equations for market price and each firm's production quantity.

The Relationship of Earlier Studies to Colorado

Much of Borenstein and Bushnell's methodology would be applicable to a restructured Colorado generation market. The treatment of the competitive fringe, both in-state and out-of-state, the handling of transmission constraints and costs, reserve requirements, and demand elasticities all could be handled in the same manner.

One difficulty is that, unlike California, Colorado could not expect to have three large firms competing in its electricity market. PSCo owns a large share of the market's generation. It would probably retain this generation unless it was directed to divest some of its assets, or unless it voluntarily agreed to divest in return for the opportunity to compete for unregulated profits or for consideration on its stranded investments.

Instead, Colorado's restructured electricity market would initially more closely resemble a dominant firm with a competitive fringe. This model will be explained in detail in chapter 5. However, it is surprising that the literature largely ignores this type of a restructured electricity market. This omission is even more surprising in light of the large number of states contemplating restructuring where one firm owns a dominant share of the generation. As these

states develop restructuring plans, analysis of the potential market power using a model with one dominant firm will be increasingly important. While mathematically less rich than a Cournot model, this type of analysis has great policy significance for many states.

Smeers (1997) suggests a way to analyze market power in a market with a dominant firm. In his view, the competitive equilibrium estimated by a simulation model provides a good starting point. Then, the researcher could calculate the markup that a dominant firm could apply to increase price over marginal cost. The researcher would add this markup to the competitive price during those times when the dominant firm could exercise market power.

This approach takes advantage of the ability of simulation models to represent accurately all of the engineering constraints present in electricity markets. These models produce an optimal solution at marginal cost. Under the Smeers approach, market power effects are then incorporated "ex post" in a simple, intuitive fashion. Essentially, this is the method that will be proposed to analyze Colorado's restructured generation market in chapter 5.

Remedies for Market Power

Across the literature, three remedies for market power consistently emerge. If none of these options appears capable of producing a competitive outcome, some form of continued regulation, such as a price cap, is suggested.

1. Require mandatory, or negotiate voluntary, divestiture of generation by firms capable of exercising market power.
2. Increase transmission capacity to "enlarge" the market and make it more contestable.
3. Implement policies to increase elasticity of demand or elasticity of supply.

Divestiture of generation in these studies is generally shown to be effective in proportion to the degree it is implemented. A limited amount of divestiture will mitigate but not eliminate market power. On the other hand, complete divestiture by the formerly regulated monopoly is shown to eliminate market power (Schmalensee and Golub 1984, 24). Whether or not complete divestiture is a viable option is a political and legal issue.

Borenstein, Bushnell, and Stoft (1997, 14) show that when transmission capacity is increased to a point where

line capacity equals peak market demand, markets will be competitive. The intuition behind this result is that this level of transmission capacity is sufficient to replace the capacity of any local firm attempting to exercise market power. This result is contingent upon the availability of low-cost, excess generation on the "other side" of the transmission constraint.

However, upgrading transmission capacity is not easily done. As Arthur Fuldner (1997, 1), an EIA operations research analyst points out, environmental concerns, potential health effects from electromagnetic fields, and concerns over transmission effects on property values have stymied the construction of many new transmission lines. While 10,127 miles of transmission lines are planned in the United States, almost all of these projects have been delayed many years. Although construction of new lines may be limited, technological advances are increasing opportunities to upgrade existing lines. Measures to relieve both thermal and voltage constraints are available. Even though it may cost as much as $500,000 per mile to upgrade a transmission line from 115 kV to 230 kV, this cost must be considered in light of the potential competitive benefits the investment would bring. Upgrading the capacity

of existing transmission paths appears to be a feasible policy option (Fuldner 1997, 1).

Measures to increase the elasticity of demand and supply are proposed as solutions to market power, but none of the studies offer simple ways of increasing price responsiveness. Essentially, this approach increases the propensity of consumers to take positive action to reduce demand or to substitute alternate sources of energy during peak demand periods. Alternatively, supply elasticity can be enhanced policies that encourage entry by new firms.

Certainly large industrial customers have the ability to reduce demand in the face of high prices. Even in a regulated environment, these firms can receive lower rates by declaring their loads interruptible. One proposal to increase the demand elasticity of small customers is to implement "real time pricing" of electricity (Borenstein, Bushnell, Kahn, and Stoft 1996, 34). Under this measure, customers would be charged prices that varied over each day with demand. Their monthly bills would detail the prices they paid at a given time of day. Whether real time pricing would affect consumer behavior significantly is unknown.

Policy makers could facilitate the elasticity of supply by simplifying siting procedures and requirements for access

to the grid. However, the desire to facilitate new supply runs headlong into the necessity to ensure system reliability. The competitive effect of reliability requirements is an issue with which organizations like NERC are currently wrestling.

In summary, the literature suggests no quick remedy to the effects of market power. Legislation to restructure may produce competitive markets in name only. The long run promises an era of technological innovation, customer choice, and lower prices. So far, the literature provides some insights on how to manage the transition from regulation to competition, but no easy answers.

Chapter 5

CONCEPTUAL FRAMEWORK

Etheridge (1995, 133) states that a conceptual framework should analyze the research problem using theory. That is the approach taken here. The potential for PSCo to exercise market power in a restructured Colorado generation market will be analyzed using a simple, microeconomic framework. While there is nothing new about this presentation, the analysis does provide a unique contribution in suggesting an approach to a problem that will be faced by states restructuring electricity where a formerly regulated utility owns a dominant share of the state's generation.

Demand

This analysis assumes that demand for electricity is linear, as proposed by Schmalensee and Golub (1984, 19). As price increases, the quantity demanded by customers falls, which produces downward-sloping demand. This behavior implies that consumers will reduce their consumption of electricity in response to a price increase.

Furthermore, with a linear demand function, if price increases a small amount, consumers would decrease their consumption of electricity slightly, while if price jumped dramatically, they would decrease consumption of electricity to a greater extent. When demand is linear, the elasticity of demand $\left(\frac{\partial Q}{\partial P} \bullet \frac{P}{Q}\right)$ varies with equilibrium price and quantity. Demand elasticity increases as quantity demanded decreases; demand elasticity decreases as quantity demanded increases (figure 25).

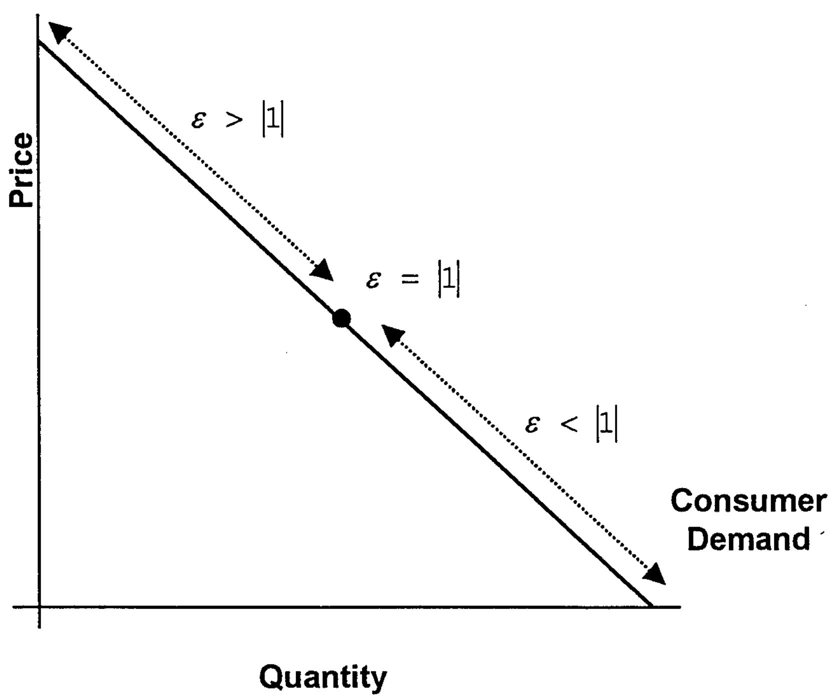


Figure 25. Linear demand and elasticity of demand.

Little is known about how consumers will adjust their demand for electricity in response to price changes in a competitive market. Some studies (Borenstein and Bushnell (1997) for example) assume electricity demand has a constant elasticity. A constant elasticity of demand function would assume that customers would increase or decrease their demand by a constant proportion in response to a change in price. Whether or not this accurately represents customer behavior is going to be an empirical issue as states implement electric restructuring. There is also a mathematical argument against using a constant elasticity of demand function unique to the circumstances of this model. A constant elasticity of demand function in a market with one dominant firm could result in extremely high, possibly infinite prices (Borenstein, Bushnell, Kahn, and Stoft 1996, 13).

The inverse demand function for linear demand is shown.

$$P = a - (b \bullet Q) \tag{5.1}$$

The elasticity of demand (ε) for a linear demand function is calculated below. Because demand slopes downward, $\varepsilon < 0$.

$$\varepsilon = \frac{\partial Q}{\partial P} \bullet \frac{P}{Q} = -\frac{1}{b} \bullet \frac{P}{Q} \tag{5.2}$$

Solving for a and b in terms of P, Q, and ε will be useful later in calculating equilibrium market conditions:

$$a = P - \frac{P}{\varepsilon} \tag{5.3}$$

$$b = -\frac{1}{\varepsilon} \bullet \frac{P}{Q} \tag{5.4}$$

Supply

In chapter 2, some key points about the supply of generation were discussed. The points most pertinent to this conceptual framework are reviewed here. Supply is an upward-sloping step function, where each step represents the incremental cost of the next most expensive plant. The horizontal "width" of a step is the rated capacity of each plant.

Furthermore, transmission capacity plays a significant role in providing the means for distant generation to enter a local market. Distant generation can enter a local market up to the capacity constraints presented by transmission grid. The cost and quantity of distant capacity must be adjusted to account for transmission losses and transmission fees.

Generation is differentiated by type as baseload, cycling, and peaking generation. Baseload generation, such as coal-fired generating stations, operates most efficiently at a constant rate. Cycling generation, including gas turbines and hydroelectric plants, easily follows the daily variations in demand. Peak generation, which may be gas- or oil-fired, is usually very expensive to operate and sits idle much of the year. During peak demand, this generation can be brought on-line from a cold start relatively quickly. When estimating the market share of generation that each company owns, contracts for firm power sales between generation companies must be considered. The long-term nature of these contracts provides the buyer control over that quantity of generation over the life of the contract.

All of these factors must be considered in the development of a region's generation supply curve. Furthermore, a supply curve may be specific to a certain level of demand. At one level of demand, transmission constraints may not be a factor, permitting supply from generation over a wide area. When transmission is constrained, a much smaller pool of local generation will constitute the supply curve.

Market Structure

If Colorado restructured its electricity industry, a competitive market equilibrium could be expected to prevail at low to moderate levels of demand. So long as there is excess generation and transmission capacity, firms will price at marginal cost rather than let their plants sit idle. On the other hand, at some threshold level of demand, transmission constraints may isolate eastern Colorado's electricity market. High demand could also exhaust the generation capacity of smaller firms, within eastern Colorado or in the rest of the Western Interconnect. When either or both of these conditions occur, eastern Colorado's electricity market would logically take the form of a dominant firm (PSCo) facing a competitive fringe.

Up to the capacity of the transmission paths into eastern Colorado, excess generation in the Wyoming and western Colorado portions of the RMPA are part of eastern Colorado's competitive fringe. Additionally, any other firms operating outside the RMPA with excess generation, subject to transmission fees and losses, could compete as part of the competitive fringe in the eastern Colorado market, as long as transmission capacity is available. Generation firms other than PSCo that are located in eastern

Colorado, since they are not dependent on transmission capacity, would always be part of eastern Colorado's competitive fringe.

Producers in the competitive fringe are price-takers. They do not have market power. Instead, they are willing to accept any market price that exceeds their marginal generation cost.

PSCo would not be able to exercise market power in eastern Colorado with the generation it owns in Wyoming or western Colorado. If PSCo attempted to increase market price with this generation, firms from the competitive fringe in these regions that are willing to price at marginal cost could be expected to undercut PSCo's plants. Therefore PSCo plants in western Colorado and Wyoming are part of the competitive fringe.

However, PSCo could strategically use its Wyoming and western Colorado plants to enhance its market power in eastern Colorado. PSCo could operate its Wyoming and western Colorado generation at maximum capacity whenever this tactic would congest the transmission paths from western Colorado and Wyoming into eastern Colorado. In this way, PSCo might be able to increase its opportunities to exercise market power.

When transmission into eastern Colorado is constrained or the supply capability of the competitive fringe is exceeded, PSCo calculates its residual demand ($D_r(P)$) as total demand (D(P)) less the supply of the competitive fringe. Over this residual demand curve, PSCo is able to act as monopolist. The residual demand is shown in figure 26. The exact shape of the residual demand curve depends on

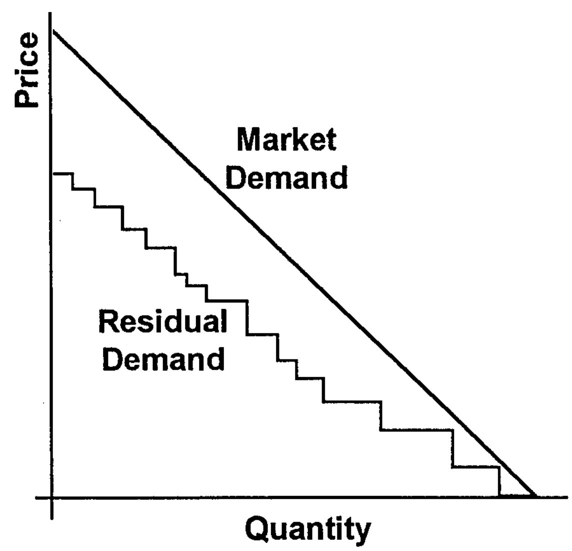


Figure 26. Calculation of residual demand.

at least two factors. When transmission constraints bind, fringe supply from outside eastern Colorado will be eliminated from the supply function. This could cause a "kink" in residual demand at the point where transmission

constraints bind. Additionally, since the supply of generation is a step function, residual demand will be non-linear.

$$D_r(P) = D(P) - S^f_{W.\,CO} - S^f_{WY} - S^f_{E.\,CO} - S^f_{Other\ WSCC} \qquad (5.5)$$

Market Equilibrium

To maximize profits over those quantities where PSCo can act as a monopolist, PSCo charges a markup of price over marginal cost. This is calculated as shown in equations 5.6 through 5.11 (P = market price, Q = market quantity, q_{PSCo} = PSCo's quantity produced, $C(q_{PSCo})$ = PSCo's generation cost).

$$\pi(q_{PSCo}) = \text{Tot.Rev.} - \text{Tot.Cost} = (P(Q) \bullet q_{PSCo}) - C(q_{PSCo}) \bullet q_{PSCo} \qquad (5.6)$$

Substituting the inverse demand function for P(Q) and $q_f + q_{PSCo}$ for Q (q_f = fringe quantity):

$$= (a - (b \bullet q_{PSCo} + q_f)) \bullet q_{PSCo} - (C(q_{PSCo}) \bullet q_{PSCo}) \qquad (5.7)$$

Assuming PSCo's business objective is to maximize profits with respect to its quantity produced (MC_{PSCo} = PSCo's marginal generation cost):

$$\frac{\partial \pi}{\partial q_{PSCo}} = a - b \bullet (q_{PSCo} + q_f) - b \bullet q_{PSCo} - MC_{PSCo} = 0 \quad (5.8)$$

Checking the second order condition to ensure this is, indeed, a maximum:

$$\frac{\partial^2 \pi}{\partial q_{PSCo}^2} = -2b - MC'_{PSCo} < 0 \qquad \therefore \pi \text{ is maximized}$$

Returning to the first order condition, the values for a and b calculated in equations 5.3 and 5.4 can now be substituted:

$$P - \frac{P}{\varepsilon} + \frac{1}{\varepsilon} \bullet \frac{P}{Q} \bullet (Q) + \frac{1}{\varepsilon} \bullet \frac{P}{Q} \bullet q_{PSCo} - MC_{PSCo} = 0 \qquad (5.9)$$

Rearranging terms and solving for price:

$$P = \frac{MC_{PSCo}}{1 - \frac{1}{|\varepsilon|} \bullet \frac{q_{PSCo}}{Q}} \qquad (5.10)$$

Calculating the Lerner index, which is the percent markup of price over marginal cost:

$$\text{Lerner Index} = \frac{P - MC_{PSCo}}{P} = \frac{1}{|\varepsilon|} \bullet \frac{q_{PSCo}}{Q} \qquad (5.11)$$

At equilibrium, PSCo supplies a market quantity where its marginal cost equals marginal revenue. Price is determined where PSCo's equilibrium quantity intersects with the residual demand curve. The competitive fringe supplies a quantity equal to the market demand at the equilibrium price, less the quantity supplied by PSCo. PSCo uses its market power to reduce quantity supplied and increase price (figure 27).

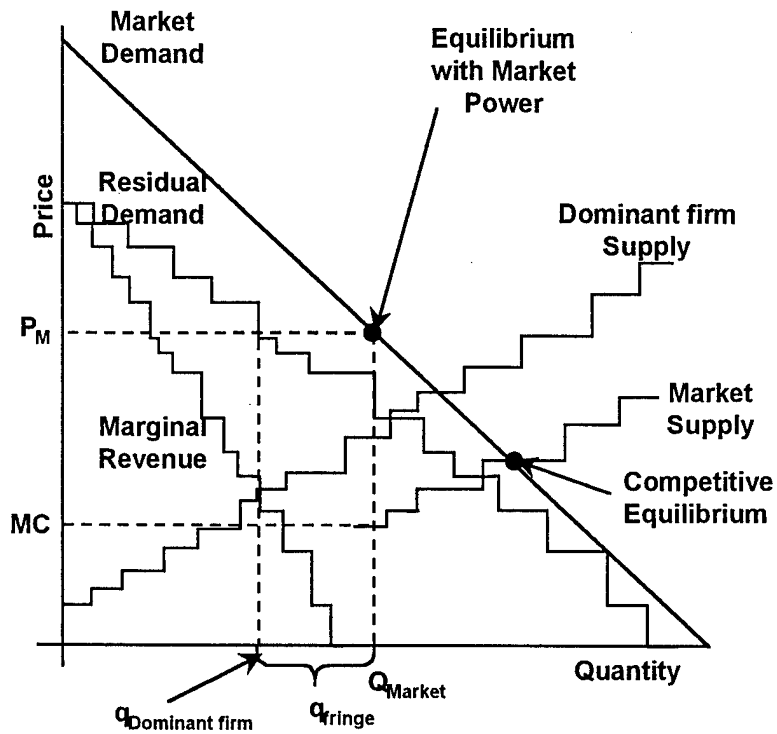


Figure 27. Comparison of equilibrium when PSCo can exercise market power with competitive equilibrium.

Equations 5.10 and 5.11 suggest several features about a restructured generation market. The second term in the denominator of equation 5.10 $\left(\frac{1}{|\varepsilon|} \bullet \frac{q_{PSCo}}{Q}\right)$ must be ≤ 1 for this equation to have any economic meaning. Furthermore, as this term approaches 1, price approaches infinity. However, there might be practical realities that would keep PSCo from increasing price as much as economic theory might suggest. Price gouging in a restructured environment would

undoubtedly invite public scrutiny and possible regulatory action. It might also motivate customers to develop alternate sources of supply and increase their elasticity of demand. PSCo could be expected to consider these long-term consequences and limit its price gouging to some extent.

Equation 5.11 also shows that the markup of market price over marginal cost is affected by two factors. One is PSCo's market share, $\frac{q_{PSCo}}{Q}$. The larger the market share of the dominant firm, the greater the markup of price over marginal cost.

The other factor is the inverse elasticity of demand, $\frac{1}{|\varepsilon|}$ suggesting that different classes of customers, if they have different demand elasticities, will face different price markups. For instance, if PSCo's generation represents 50% of the eastern Colorado market at a given level of demand, a large industrial customer has a demand elasticity of $|0.9|$, the optimal price markup for PSCo would be 55% above marginal cost. However, a smaller customer with a demand elasticity of $|0.4|$, could face a price 125% above PSCo's marginal cost. A residential customer, whose

elasticity of demand may be as low as $|0.1|$, could face a price as high as 500% above marginal cost.

Policy Implications

These results have clear policy implications. Elasticity of demand plays a crucial role because it has a multiplier effect on the price markup. Small increases in the elasticity of demand could significantly reduce the markup of price over marginal cost.

If there is a great difference in elasticity of demand among classes of customers, each class could face much different prices. Large industrial customers, who have self-generation options, may be able to negotiate much better deals than residential customers. To "level the playing field," state policy makers could enact measures to increase the elasticity of demand of small customers. One way to do this would be to encourage the market presence of "load aggregators." These firms contract with groups of small customers to collectively represent their demand, thus giving small customers greater bargaining power. If load aggregators negotiate long term contracts for generation on behalf of their customers, the agreed on price may more

closely reflect a long-term, more elastic demand function. This could reduce price markups.

More sophisticated metering and billing of electricity that incorporates "real time" pricing might also increase a customer's demand elasticity. If customers are made aware of the way electricity prices vary, they might undertake measures to reduce demand during peak periods. Installing a home thermostat that reduces home heating or air conditioning during the day is a simple measure customers might choose to reduce their electricity consumption during peak demand periods. Other measures such as "smart" appliances that automatically reduce their use of electricity during peak periods may improve elasticity of demand in the long run.

The anecdotal evidence on the effectiveness of measures to increase demand elasticity, however, is not good. For instance, the city of Longmont, Colorado, offered its customers a device to limit electricity consumption during peak periods a few years ago. There were few takers (Allum 1997).

Equation 5.11 also suggests that measures to reduce the market share of the dominant firm will reduce price markup, although perhaps not as dramatically as increasing demand

elasticity. All measures that reduce the market share of the dominant firm would be theoretically equivalent. Divestiture of generation by PSCo, market entry by new generation firms, or increases in transmission capacity, assuming excess generation is available in other regions would all have the same effect.

If policy measures affect price markup similarly, it would seem sensible for state policy makers to favor those measures that reduce PSCo's market share at the least cost. Voluntary divestiture of some portion of its generation by PSCo would immediately reduce, although perhaps not eliminate, PSCo's market power. Policies to encourage investment in new generation by the private sector might be less costly to the public than public investments to increase transmission capacity. Private investment in new generation would seem even more favorable over public transmission investments if there was no assurance that an investment in new transmission capacity to eastern Colorado would actually result in entry by distant firms.

A Utah firm with excess generation (Pacificorp, for example), might have a choice between exporting power to Colorado or to California. This firm could choose to sell its power in California, if it could expect to earn a higher

price there. "Build it and they will come" might not apply to investments in transmission capacity, given that there may be better profit opportunities on the grid.

Additionally, investments to increase transmission capacity would be of little value if there were no firms with excess capacity on the grid to take advantage of it. The WSCC's forecast of generation reserve margins (table 5) suggests that the long-term availability of excess generation capacity is not good. Load growth is gradually eliminating excess capacity. Furthermore, if other western states also restructure electricity, competitive firms could choose to retire excess, uneconomic capacity. These factors increase the risk associated with public investments in transmission capacity.

Implications of the Conceptual Framework

Microeconomic analysis offers a straightforward means to address the problem of market power in Colorado's restructured electricity market. Market power can be measured using the Lerner Index, which is the difference between market price and marginal cost. Additionally, policy makers would be interested to know what portion of a given year PSCo could cause prices to exceed marginal cost.

These measures will be a function of customer demand and transmission constraints. When generation capacity is exhausted or transmission constraints occur, PSCo will be able to exercise market power. These issues will be central to the methodology required to analyze market power.

Chapter 6

METHODOLOGY

The approach that will be used to analyze the potential for PSCo's market power in a restructured Colorado generation market is straightforward and flows from the study objectives and conceptual framework. The first step in the method is to estimate a competitive equilibrium in the eastern Colorado, western Colorado, and Wyoming portions of the RMPA, using only generation resident in each regions. This equilibrium is estimated for each region using an electric utility production cost simulation, Elfin. Second, the interaction between regions is modeled on a spreadsheet using Elfin's output. Generation located in each region of the RMPA is assumed to serve its native load first. Uncommitted generation is then assumed to be available to be exported over the grid to other markets. Uncommitted generation in eastern Colorado, western Colorado, and Wyoming is available to compete for market share against PSCo in Colorado's restructured generation market. When transmission capacity into eastern Colorado is constrained,

or when the supply of uncommitted fringe generation is less than the quantity of generation supplied to the market by PSCo, PSCo can apply a price mark-up to marginal cost.

$$\text{Lerner Index} = \frac{P - MC_{PSCo}}{P} = \frac{1}{|\varepsilon|} \bullet \frac{q_{PSCo}}{Q} \qquad (6.1)$$

The extent and duration of this price markup provide a measure of PSCo's market power. The third step is to estimate the effects of alternative scenarios under which PSCo's market power might be mitigated. The rest of this chapter will address this methodology in greater detail.

Scope of the Study and Data Sources

This study will cover the period 2002-2005. The earliest date to implement electric restructuring in Colorado on draft bills currently under consideration by the legislature is 2002. Ending the simulation in 2005 provides a range of dates that incorporates the effects of load growth, the expiration of contracts with independent power producers, and the construction of currently planned generation.

Over this time, the model is a short-run analysis. It analyzes PSCo's market power in eastern Colorado's generation market assuming current and currently planned

generation and transmission. In general, market entry by new firms is not modeled. However, at the request of the Colorado PUC, on whose behalf this research is conducted, one scenario considers the construction of 1,000 MW of fringe generation in eastern Colorado, or the entry of 1,000 MW of fringe generation over the transmission grid.

Demand data from each region is taken from the WSCC's Summary of Existing Loads and Resources, dated January 1, 1997 (included on diskette). Since the WSCC forecast is for the RMPA as a whole, this demand must be apportioned to eastern Colorado, western Colorado, and Wyoming. Apportioning total RMPA demand to each sub-region is done on the basis of the 1995 net energy sales of each region (p. 68). The shape of the load curve for each region within the RMPA is assumed to be the same as the overall RMPA load curve.

Data on generation cost is as collected by RDI and from FERC Form 1 submissions for PSCo, WestPlains Energy, Colorado Springs Municipal Utilities, Tri-State, and WestPlains Energy. (appendix A). The model's generation set also incorporates the effects of firm and contingent firm power contracts as collected by RDI (appendix B). The model assumes that when a company has a contract to purchase firm

power, it has control over that portion of the seller's generation for the duration of the contract. Contingent firm power requires the seller to provide power to the buyer whenever that capacity is not required to serve the seller's own customers. Some of these contracts expire during 2002-2005. Upon expiration of the contract, full control of a plant's output reverts to the owner of the generation.

The WSCC (1997c, 367) documents planned generation additions by year. The Integrated Resource Plans of PSCo and WestPlains Energy contain additional detail on planned generation construction. These planned resources are assumed to come into operation as forecast.

A number of reliability criteria set reserve requirements in the WSCC. This model assumes an overall system spinning reserve requirement of 7% of non-hydroelectric generation, as Borenstein and Bushnell's study did (1997, 16).

Elfin

Elfin, an electric utility financial and production cost model developed by the Environmental Defense Fund (EDF), will be used to compute a competitive equilibrium for each region within the RMPA. Elfin was initially developed

in the 1970s. Over the past two decades, Elfin has been frequently updated and refined. Numerous utilities, government agencies, and public interest groups in the United States and internationally, have used this software for policy analysis (EDF 1996, 1).

Elfin is a Windows-based model that runs on desktop computers. Elfin dispatches generation to service demand in order of increasing cost, subject to the engineering constraints unique to each type of generation. Elfin incorporates many of the nuances that affect the dispatch of generation such as reserve requirements, outage rates, limitations on the use of hydroelectric generation, and the load-following constraints of baseload generation. Elfin will be employed in conjunction with spreadsheet analysis as described below.

Step 1

The Elfin model will be used initially to estimate a competitive equilibrium in the eastern Colorado, western Colorado, and Wyoming markets, using only the generation native to each region. Firm power contracts and exchanges between the RMPA and the Northwest Power Pool (NWPP), Mid-America Power Pool (MAPP), and Southwest Power Pool (SPP),

as projected by the WSCC, will be treated as part of Wyoming's demand. Firm power contracts and exchanges between the RMPA and the Arizona-New Mexico and California-Nevada portions of the WSCC, as projected by the WSCC, will be considered part of western Colorado's demand.

Step 1 identifies excess generation capacity in western Colorado and Wyoming available to supply eastern Colorado up to the capacity of transmission paths linking these regions. The key data obtained from Elfin are the economic dispatch order, time marginal for each plant, PSCo's market share in eastern Colorado, and the excess fringe generation available in eastern Colorado, western Colorado, and Wyoming.

The first step in Elfin is to input an hourly load curve for each region. This data is obtained from the 1996 FERC Form 714s (hourly load data) submitted by the six RMPA control centers: Black Hills Power, WAPA, Platte River Power Authority, PSCo, Colorado Springs Municipal Utilities, and WestPlains Energy. The hourly load from each control area is added together to get the overall RMPA hourly load curve. Figure 28 reflects the load for each hour of 1996 from 1 AM, January 1st through midnight on December 31st (8,784 periods, since 1996 is a leap year).

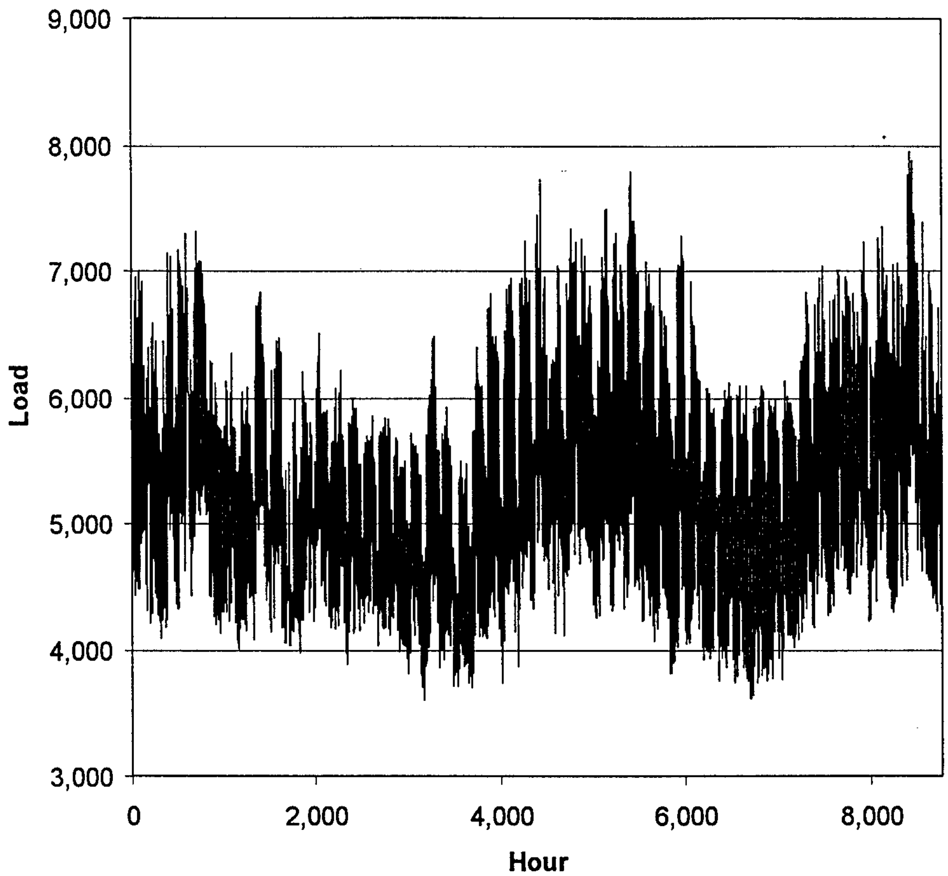


Figure 28. 1996 RMPA hourly load curve.

To run Elfin for each region separately, the RMPA overall hourly load curve must be scaled appropriately for each sub-region. This is done on the basis of the net energy sales by utilities from each region (p. 68). The underlying assumption is that the shape of the overall RMPA hourly load curve is the same for each sub-region. To investigate the validity of this assumption, a correlation analysis was performed among the FERC Form 714 data from each control center. The results are shown in table 10.

Table 10.

Correlation Analysis of FERC Form 714 Hourly Load Data

	BHPL	CSU	PRPA	PSCo	WAPA	WestPlains
BHPL	1					
CSU	0.8750	1				
PRPA	0.8994	0.9819	1			
PSCo	0.8333	0.9309	0.9413	1		
WAPA	0.4606	0.3154	0.3743	0.3876	1	
WestPlains	0.8488	0.9534	0.9593	0.9443	0.4141	1

Overall, the assumption is reasonable for all control areas except for WAPA. While the correlation remains positive between WAPA and the other control areas, the similarity in the way load varies for WAPA's customers and the way load varies for the other control centers is not as great. This problem introduces some error into the model's

output. However, WAPA's load is only 22% of the overall RMPA load. Furthermore, much of the generation of this control area is tied to its native load and not expected to be able to compete in a structured market anyway. Additionally, this assumption is the basis for allowing any kind of aggregate comparisons to done between regions of the RMPA. The alternative requires that any calculations be done on an hour-by-hour basis (8,760 periods per year). Any analysis of market power would become intractable.

Figure 29 provides evidence of the difference in the shape of the load curves for each region, using the second week in January 1996 as an example. The similarities between the load shape from each control center, other than WAPA, are readily apparent. WAPA's differences are a stark contrast. The other five control areas see demand increase rapidly each day through mid-morning. This would coincide with times when most people get up in the morning, and businesses open. Then, demand plateaus for a few hours, only to increase again in the early evening hours, when most people are going home from work, cooking meals, watching television, and so forth. Demand diminishes through the evening hours.

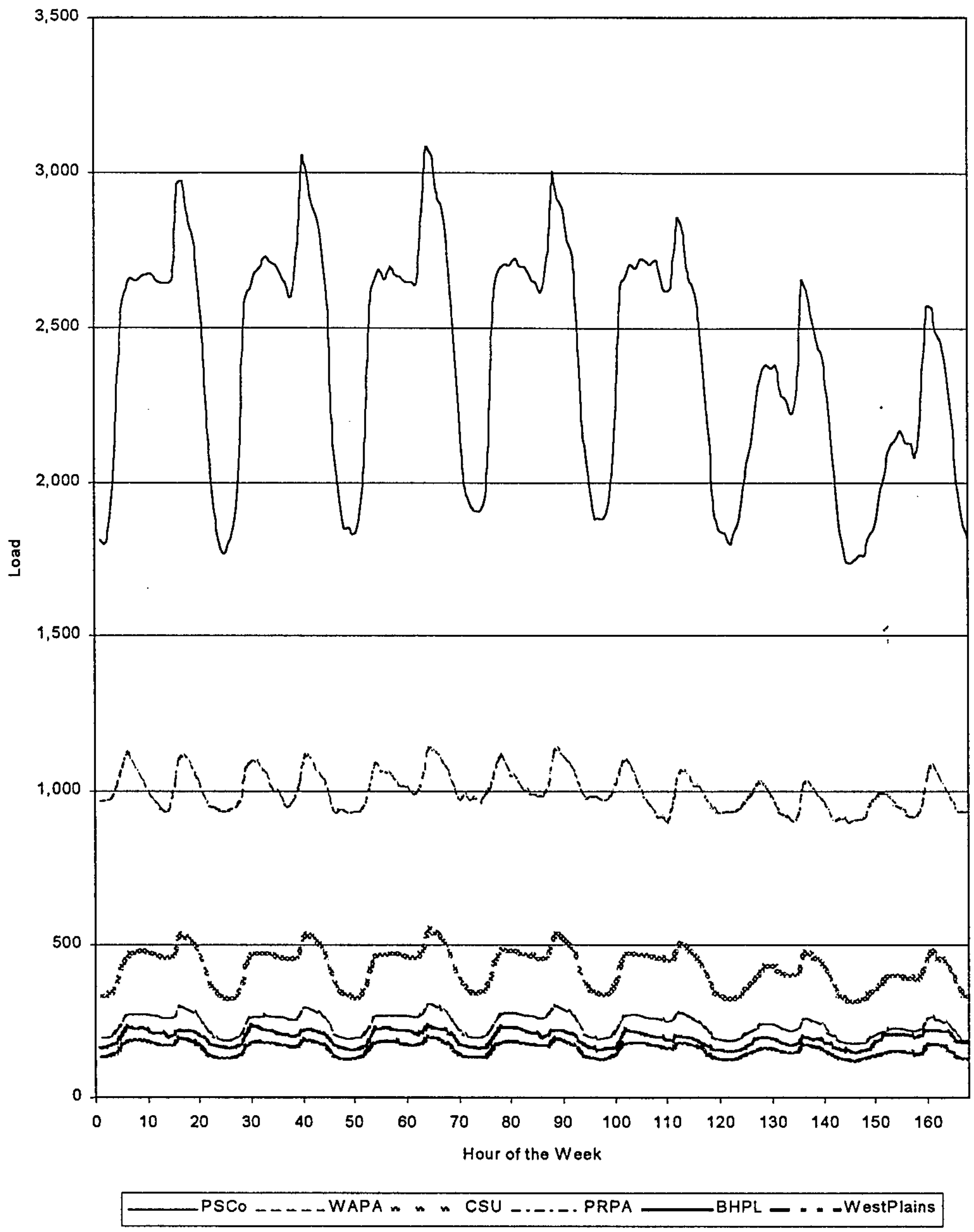


Figure 29. Comparison of hourly load data for each control center in the RMPA for the 2nd week of January, 1996.

The significant difference in WAPA's demand is that the mid-day plateau, which is present in the five other control centers, does not occur in WAPA's control area. Demand ramps up quickly in the morning hours as in other RMPA control areas. However, after the initial increase, it then gradually declines until it ramps up again in the early evening hours. The early morning peak is not sustained throughout the day, as it is in other RMPA control areas. A possible explanation for this difference lies in the fact that the WAPA control area's demand is largely rural. WAPA's Loveland, Colorado, control center includes demand for Basin Electric Power Cooperative, Tri-State, MEAN, the Rocky Mountain Generation Cooperative, and the Wyoming Municipal Power Agency. These firms serve a significantly higher portion of rural customers than do the other five control centers. Something in the electrical demand of rural customers produces a differently shaped load curve.

Since the goal of this analysis is to gain a general appreciation of whether PSCo's market power is a significant concern, the analysis will proceed in spite of this hurdle. There are many, many uncertainties about how Colorado's restructured electricity market will operate. As these

issues are resolved, a more detailed analysis that incorporates differences in load shape may be appropriate.

Step 2

Elfin's output is then exported into a spreadsheet model for further analysis. In Step 1, the Elfin model calculated PSCo's eastern Colorado market share in the absence of imports from other regions. In Step 2, excess fringe generation in eastern Colorado, western Colorado and Wyoming, representing the total fringe quantity available to mitigate PSCo's market power (q_f), is compared to the market share of PSCo in eastern Colorado at each level of demand.

Excess generation in these regions, adjusted for transmission losses and transmission charges (equations 4.5 and 4.6), is assumed to be available to enter the eastern Colorado market. If the sum of the adjusted excess capacity in these regions, up to the level of transmission capacity, is greater than PSCo's eastern Colorado market share, PSCo will not be able exercise market power in the eastern Colorado generation market.

However, once fringe supply is constrained, either because of limited generation capacity or due to transmission constraints, then PSCo could charge a price

markup over marginal cost for its generation (equation 6.1). Calculating the extent and duration of price markups will provide a measure of PSCo's market power.

As discussed in chapter 3, electric restructuring in Colorado would probably be limited to the service areas of the state's Investor-Owned Utilities, PSCo and WestPlains Energy. Therefore, the relevant market quantity (Q) over which PSCo might be able to exercise market power would be the sum of the forecasted demand for PSCo and WestPlains Energy. The data required to calculate "Q" is drawn from company forecasts of their customer demand contained in their IRPs.

The other major variable in calculating PSCo's markup is the price elasticity of demand of customers. Studies of market power from the University of California Energy Institute have estimated this elasticity over a range of $|0.1|$ to $|0.9|$. Studies by the Energy Information Administration have estimated the range at $|0.15|$ to $|0.5|$. This analysis will use the range $|0.1|$ to $|0.9|$ to get a broad range of elasticities. PSCo's markup will be estimated at customer elasticities of $|0.1|$, $|0.4|$, $|0.7|$, and $|0.9|$ to reflect the markups that various customer

classes (residential, small commercial, large commercial, and industrial) might face.

This analysis is performed over what is commonly called a load duration curve (figure 30). In a load duration curve, hourly load data is sorted from largest load (peak demand) to smallest load over a given period of time, in this case, a year.

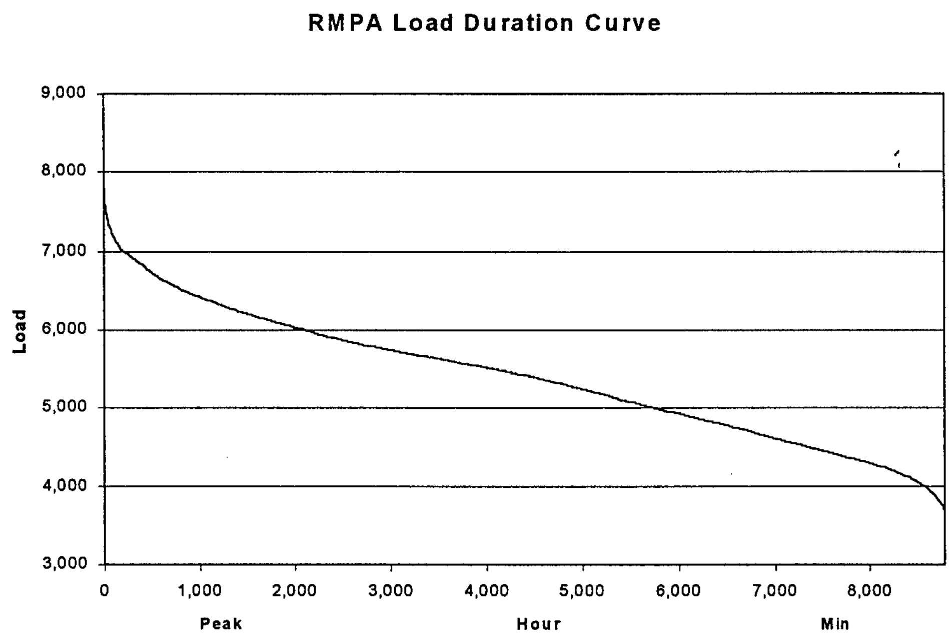


Figure 30. RMPA load duration curve.

The Elfin simulation calculates two key elements of data, economic dispatch order and time marginal for each plant. The economic dispatch order tells how to array

plants against the load duration curve (figure 31). The time marginal for each plant tells what portion of a year each plant is marginal along the load duration curve. For the time each plant is marginal, PSCo's market share can be calculated.

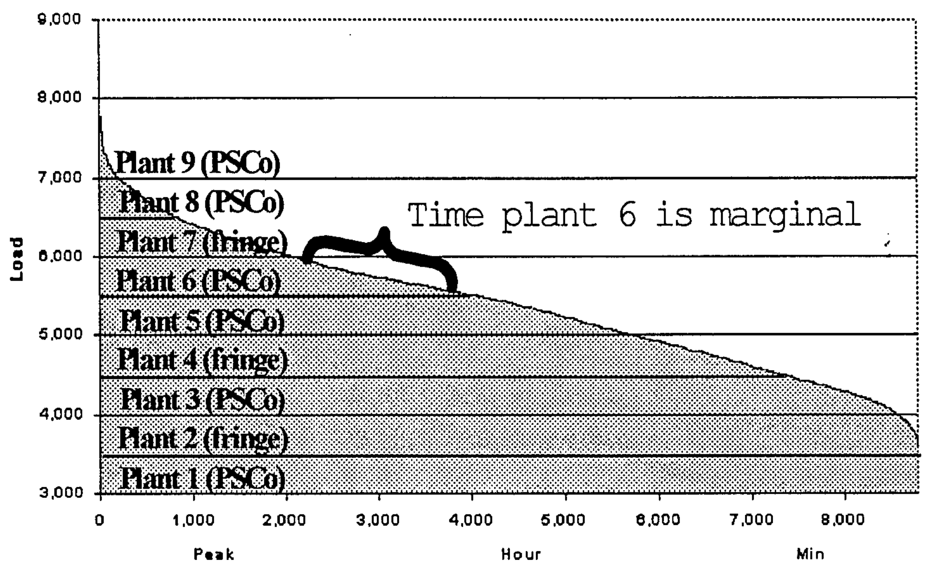


Figure 31. Use of economic dispatch order and time marginal.

To incorporate the effect of competition PSCo would experience if it attempted to exert market power, the uncommitted fringe generation must be identified at each point along the load duration curve (figure 32). At a given point on the load duration curve, PSCo owns a certain share of the eastern Colorado market. At that same point, a

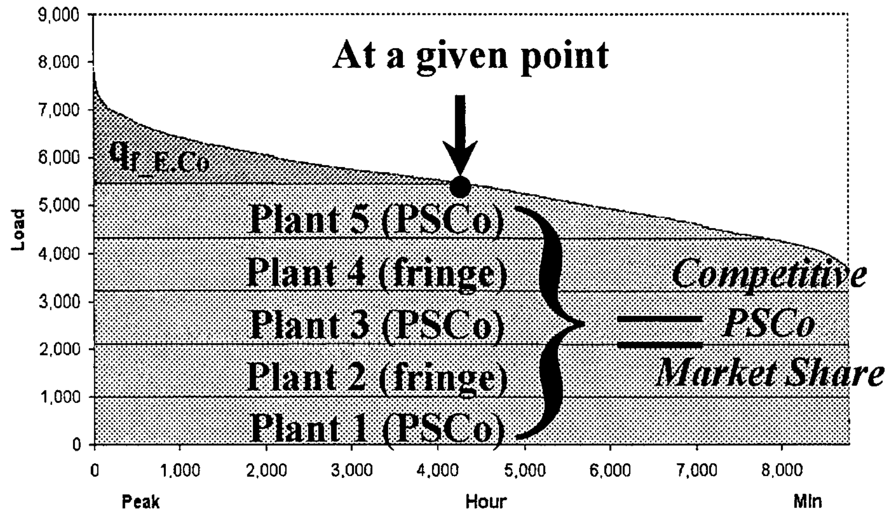


Figure 32. PSCo's competitive market share in eastern Colorado and identification of uncommitted eastern Colorado fringe generation.

certain quantity of eastern Colorado fringe generation ($q_{f\_E.Co}$) is uncommitted and available to enter the market should PSCo attempt to exert market power by restricting output or increasing price.

At the same point on the load duration curve for Wyoming and western Colorado, the quantity of fringe generation that is not committed to serve native load can be identified ($q_{f\_W.Co}$, q_{f_Wyo}). This uncommitted fringe generation is available to enter the eastern Colorado market up to the level permitted by transmission constraints (figure 33). The critical nature of the assumption that the

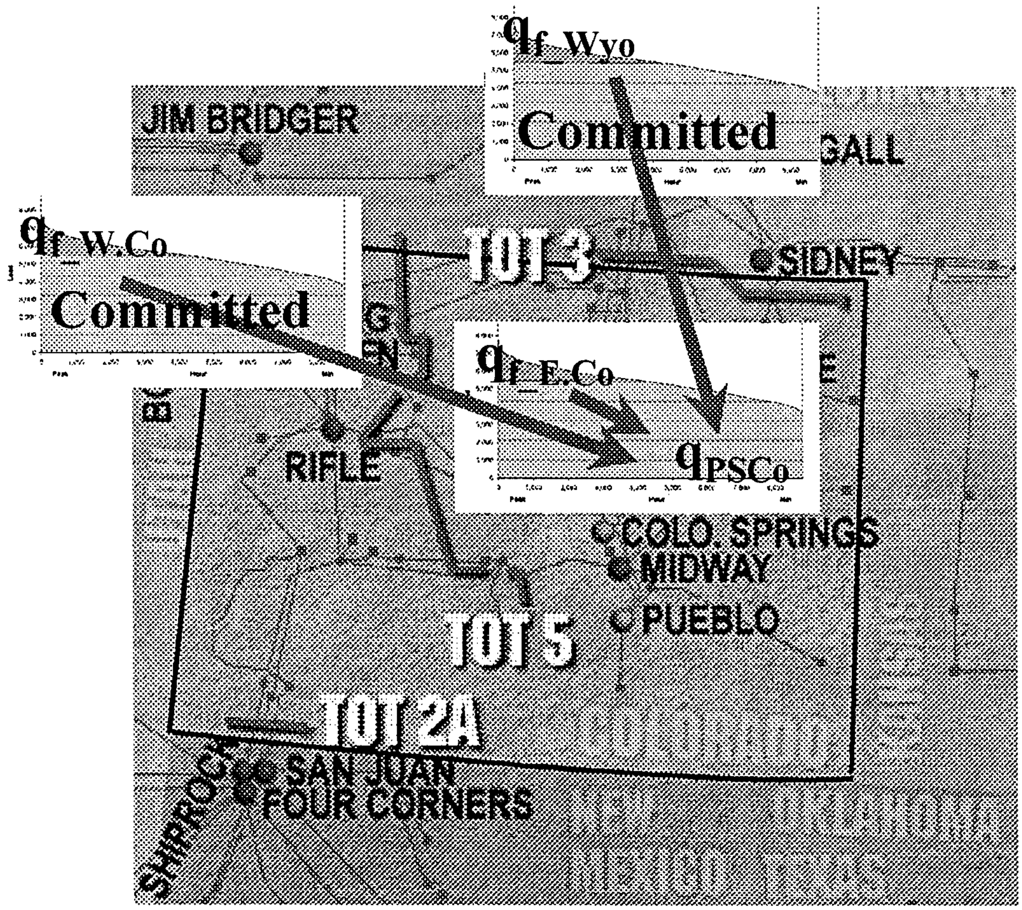


Figure 33. Identification of uncommitted fringe generation in eastern Colorado, western Colorado, and Wyoming

shape of the load curve is the same for the entire RMPA is now apparent. This assumption permits the analysis to work off a load duration curve, instead of the hourly load curve (figure 28). Performing the comparisons on an hourly load curve would require 8,760 comparisons between each region. With the assumption that the hourly load curves are the

same, the load duration curves between regions can be compared. The number of comparisons required is reduced to 50-60 for each region, which is the number of plants that are actually marginal at some point on the load duration curve.

It is not merely the task of comparing 8,760 data points that is difficult. The problem is that the Elfin model would be required to recalculate and print output for each hour of the year. In its current mode of operation, it performs hourly calculations, but then aggregates that output over a specified time, which can be from a week to a year. Exporting hourly output from Elfin to a spreadsheet to perform a market power analysis would be an enormous undertaking, and one which Elfin is not designed to perform.

Once the uncommitted fringe generation is identified in eastern Colorado, western Colorado, and Wyoming, PSCo's market share if an attempt were made to exercise market power is simply

$$\text{PSCo Adjusted Market Share} = \frac{q_{PSCo} - q_{f\_E.Co} - q_{f\_W.Co} - q_{f\_Wyo}}{Q_{Market}} \quad (6.2)$$

In this case, q_{PSCo} is the quantity PSCo would supply if the market was competitive, and $q_{f\_E.Co}$, $q_{f\_W.Co}$ and q_{f_Wyo} are the quantities of uncommitted generation in each region.

PSCo's adjusted market share (the quantity it supplies when exercising market power) can then be used in equation 6.1 to calculate PSCo's markup over marginal cost. This calculation is repeated along the load duration curve whenever a different plant in any region becomes marginal. The Elfin output, instructions on how to export Elfin's output into a spreadsheet and perform the market power calculations, as well as the spreadsheets that perform these calculations are on diskette.

The base case scenario (Scenario 1) attempts to capture all of the factors of the current and currently forecasted factors that affect the RMPA electricity market. The factors include current and planned generation, load growth, contracts, joint ownership agreements, transmission constraints, and interactions with other regions. Following is a summary of the significant assumptions related to this model.

1. Time period of interest: 2002-2005.

2. Elasticity of demand: $|0.9|$, $|0.7|$, $|0.4|$ and $|0.1|$.

3. Reserve margin for spinning reserve: 7%.

4. Competition occurs in the service territories of the state's IOUs: PSCo and WestPlains Energy.
5. PSCo does not renew contracts for independent producers as they expire; after contract expiration these plants become part of the competitive fringe.
6. Fringe generation serves its native load first; uncommitted fringe generation competes for PSCo's market share.
7. All fringe generation within the RMPA competes for PSCo's market share (5,000 MW, 2002-2005, of which 1,700-1,900 is physically located in eastern Colorado-exact quantities vary by year).
8. Due to declining reserve margins in the rest of the WSCC, and competition in other states with higher generation prices, no generation outside the RMPA competes for PSCo's market share.
9. The shape of the hourly load curve for each region is the same.

Step 3

In this step, alternative scenarios are modeled to calculate the effect of various conditions on PSCo's market power. As these policies cause the parameters of the model to change, Steps 1 and 2 will be performed under the new conditions so that the extent and duration of price markups can again be estimated. The following scenarios are considered:

Scenario 2. Assume that transmission constraints (TOTs 3 and 5) do not affect the flow of power within the RMPA. A detailed cost-benefit analysis of increasing transmission to the level required to facilitate this capability is beyond the scope of this study. The intent here is merely to provide an estimate of how PSCo's market power in eastern Colorado might be affected when transmission constraints are relaxed.

Scenario 3. Assume that ten 100 MW gas-fired plants owned by fringe firms are constructed in eastern Colorado. While entry is not normally modeled in a short-run economic analysis, the intent of this scenario is to provide the Colorado Public

Utilities Commission with some idea of the effect of entry by fringe firms on PSCo's market power. These plants are assumed to operate with the cost characteristics of PSCo's Fort St. Vrain plant. Alternatively, this scenario could also model the entry of 1,000 MW of generation over the transmission grid from beyond the boundaries of the RMPA, or some combination of new construction in eastern Colorado and entry over the grid.

Scenario 4. Assume that as part of an agreement to implement electric restructuring, PSCo agrees to voluntarily divest 50% of its generation. PSCo might be motivated to do this in return for the opportunity to compete for unregulated profits or to receive compensation for its stranded investments. Divested plants are assumed to become part of the competitive fringe. This implies that one company is unable to purchase all plants divested by PSCo. To implement divestiture, this scenario assumes that PSCo sells a 50% interest in each of its generation resources. While admittedly, this is not the

approach that would ever be implemented, calculating divestiture in this way avoids complications that could arise if PSCo sold off only baseload generation, or peaking generation, or particular plants that, because of their location on the grid, were in a "must-run" status.

As part of each scenario, the effects of making the demand for generation more price responsive will be considered. PSCo's markup at each of the price elasticities indicated will be compared ($|0.1|$, $|0.4|$, $|0.7|$, and $|0.9|$). These calculations will provide an indication of the effect of improving demand elasticity. Possible policy measures to improve the price elasticity of demand include encouraging the presence of load aggregators, or requirements that utilities provide detailed, time-of-day price information on electric bills. Whether or not these measures would actually increase demand elasticity is an empirical issue.

Chapter 7

ANALYSIS AND FINDINGS

Overall, the results of this model show that PSCo can exercise a large degree of market power in a restructured Colorado electricity market. In the base case scenario, PSCo can apply a markup over marginal cost greater than 93% of the year, each year from 2002 through 2005. The average markups customers would face are a function of the price elasticity of demand. Average markups for 2002 range from 53% for an elasticity of demand of $|0.9|$ to 478% for an elasticity of demand of $|0.1|$. It would be unlikely that PSCo would actually apply the full markup in any case. Price gouging of this magnitude would probably invite re-regulation, encourage customers to seek other suppliers and reduce or shift load, and encourage other firms to construct new generation in eastern Colorado. Rather, it is more likely that PSCo would attempt to select a profit margin that satisfies its shareholders, does not incur the wrath of Colorado consumers, and does not invite entry by new firms.

More importantly, as the debate over electric restructuring in Colorado proceeds, the results suggest that competition will not force prices to marginal cost for a significant portion of the year. Studies that purport to calculate the economic benefits of electric restructuring rely on price forecasts. These studies must consider the possibility that prices will be above marginal cost and include some type of sensitivity analysis for price. Any ex ante estimation of stranded costs also takes market prices into consideration. Currently, RDI (1997, SC-2) and Moody's Investor Services (McGraw-Hill Energy and Business Newsletters 1997, 14), using models that assume prices under electric restructuring will be at marginal cost, predict that PSCo has negative stranded generation costs. In other words, the current book value of their generation is less than that generation will be worth in a competitive environment. If price, in fact, exceeds marginal cost, PSCo's generation will be even more valuable than RDI and Moodys currently estimate.

The other significant result suggested by this model is that if a utility is able to segregate the market by customer class, price markups could vary substantially among customer classes. Specifically, customers with a price

elasticity of demand of $|0.1|$ face a price markup nine times greater than customers with a price elasticity of demand of $|0.9|$. Restructuring legislation should consider carefully the market institutions the plan implements. Policy makers should strive to design market structures that would treat each customer class fairly. A common pool that all firms and customers bid into for short-term energy sales would be one option. The pool would set the price for all customers, regardless of class. For long-term needs, large industrial customers have an advantage over residential customers in negotiating deals because of the size of their loads. Nevertheless, if the restructured market encourages the presence of load aggregators who represent many small customers, this might prove to be an effective means of leveling the playing field.

In terms of mitigation strategies, relaxing transmission constraints within the RMPA does not seem to affect the portion of the year over which PSCo can exercise a markup, or the amount of markups that are applied. The reason why this occurs is that there is simply not enough uncommitted fringe generation in western Colorado and Wyoming during the periods when PSCo can apply a markup to

make the transmission constraints an issue. It appears that the transmission constraints would become important only if firms beyond the RMPA (in Arizona-New Mexico, or the Northwest Power Pool) attempted to compete with PSCo in eastern Colorado. Whether firms would be motivated or capable of doing this is questionable. Certainly, if PSCo attempted to apply its maximum markup, and eastern Colorado generation prices were inordinately high, firms from other regions would want to sell their excess generation in eastern Colorado. However, there are other states on the western grid that already have higher energy prices, such as California. California also has a large head start on electric restructuring, relative to other states. It is conceivable that much of the western grid's excess generation could be already committed to customers in California by the time Colorado implements electric restructuring. The significant investment that would be required to increase the transmission capability of TOT's 3 and 5 appears risky in light of these uncertainties.

The entry of new fringe generation appears to have a limited, but negative effect upon PSCo's ability to exercise market power. Over the period 2002-2005, the time of year over which PSCo could apply a price markup falls from in

excess of 93% to in excess of 74%. The amount of the price markups that can be applied is similarly reduced. Furthermore, if some entry occurs, the threat of even more entry in the long run becomes more credible. In accordance with Baumol's (1982, 5) theory of contestable markets, the threat of competition could be a disciplining influence on PSCo's pricing strategy.

On the other hand, in the UK market, the generation market share of the two largest firms declined between 1990 and 1995 from 74% to 54% because of entry by new firms and generation retirements. The two large firms continued to exert market power keeping prices well above marginal cost during this period (Wolak and Patrick 1997, 7). Given PSCo's large market share and the length of time required to construct new generation, it might take a very long time for entry to put much of a dent in PSCo's ability to exercise market power. Additionally, firms constructing new generation have the option of building in the market with the greatest profit potential. Whether firms would choose to build generation in eastern Colorado, where reserve margins are expected to remain above 15% through 2006 (WSCC 1997b, 38), instead of California or some other market with

a greater population density, lower reserve margins, and already higher energy prices is a serious concern.

The scenario where PSCo divests 50% of its generation appears to offer the greatest reduction in the portion of the year, as well as the amount of the markups. PSCo can apply a markup over marginal cost 47% of the year or less during 2002-2005. The average markup is approximately one-eighth of the markup of the base case. Divestiture of generation, either voluntarily or mandated, might have appeared to be a pipe dream only a few years ago. However, it has become somewhat common as part of the implementation of restructuring plans. The Montana Power Company (MPC) recently announced that it would divest 100% of its generation as part of the state's electric restructuring. MPC voluntarily agreed to this measure in return for favorable consideration by Montana's policy makers on its stranded costs. The three largest California utilities agreed to divest 50% of their generation as part of that state's electric restructuring. Some New England utilities are also divesting portions of their generation as part of state restructuring plans. Of course, to increase competition, the generation of the dominant firm cannot be divested entirely to another firm. The divestiture plan

must somehow ensure that the divested generation becomes part of the competitive fringe.

Base Case

Under the base case scenario, price markups are faced by customers in eastern Colorado most of the year and vary by customer class (figure 34). To summarize, PSCo can

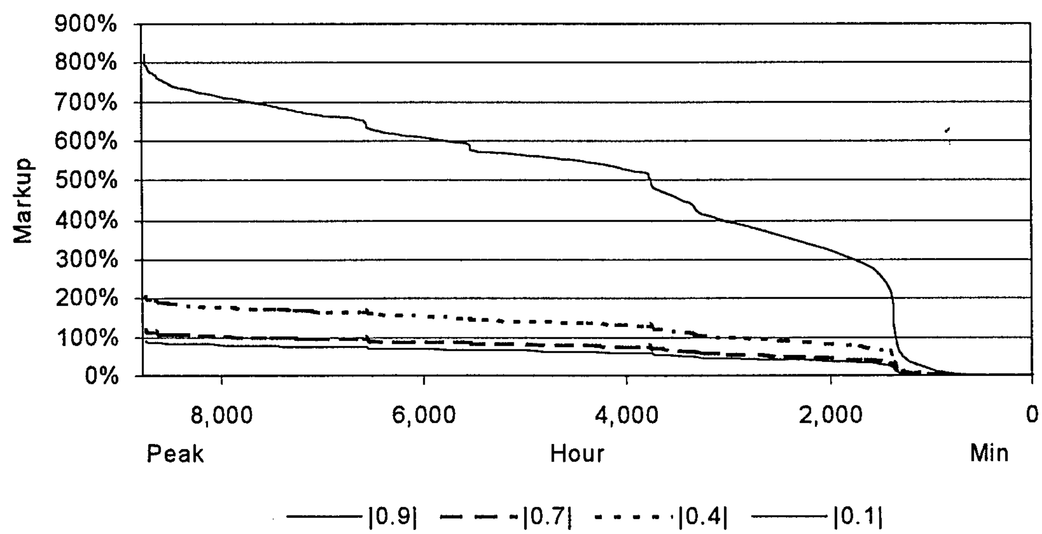


Figure 34. Markups PSCo can apply over marginal cost given a range of price elasticities of demand in 2002, base case scenario.

charge a markup 93% of the year. Only at very low levels of demand is there enough uncommitted fringe generation to prevent PSCo from charging a price markup over marginal

cost. PSCo creates this markup by acting as a dominant firm and restricting its output (table 11). The results vary widely over the range of elasticities (figure 35).

Table 11.

Base Case Scenario Summary

	2002	2003	2004	2005
Competitive market share	87%	87%	85%	85%
Share with price markup	53%	54%	50%	51%
% of year markup applied	93%	95%	94%	96%
Elasticity	Average Markup			
0.9	53%	55%	50%	53%
0.7	68%	71%	65%	68%
0.4	120%	125%	113%	119%
0.1	478%	498%	452%	474%
Elasticity	Average Price			
0.9	$21.90	$25.17	$27.34	$31.61
0.7	$24.07	$27.73	$29.95	$34.72
0.4	$31.40	$36.37	$38.76	$45.24
0.1	$82.69	$96.89	$100.42	$118.86

The results obtained in 2002 are similar to the results obtained in 2003-2005. Over this time, RMPA load is growing at a rate of approximately 2% a year. Additionally, PSCo is constructing more generation each year. However, over this same time, some of PSCo's contracts with independent power producers and qualifying facilities expire. As these contracts expire, the plants are assumed to become part of the competitive fringe. Additionally, during this time

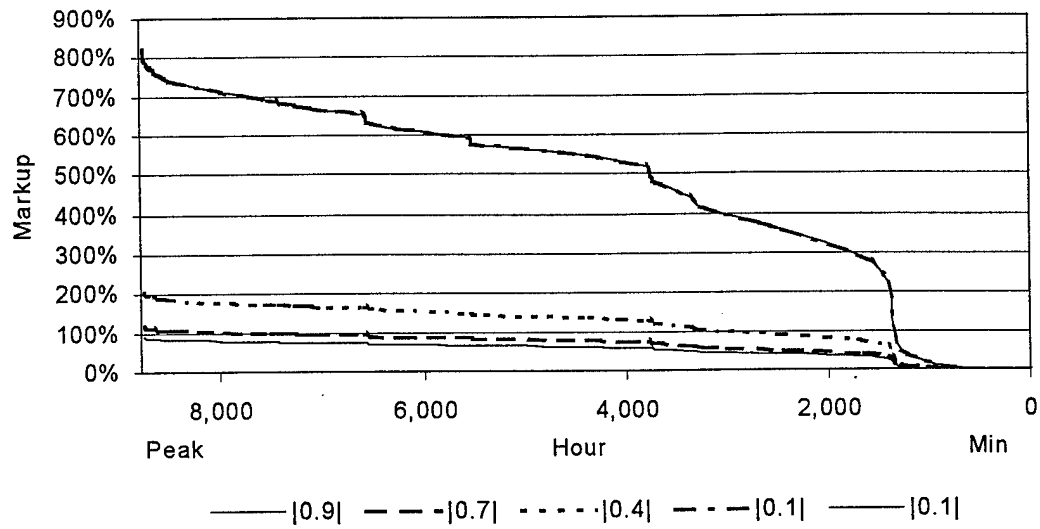


Figure 35. Markups PSCo can apply over marginal cost given a range of price elasticities of demand in 2002, assuming that the TOT 3 and TOT 5 transmission constraints are relaxed.

Colorado Springs Municipal Utilities and WestPlains Energy are constructing new generation. The overall effect is that price markups do not change much.

PSCo acts as a dominant firm by trading market share for price markup. This strategy does more than merely maximize PSCo's profits in eastern Colorado. PSCo can then sell the generation it withholds from the eastern Colorado market in other restructured markets on the western grid or through power marketers.

Relaxing Transmission Constraints on TOT 3 and 5

The surprising result of this scenario is that relaxing transmission constraints within the RMPA region makes almost no difference in the portion of a year over which PSCo can apply a markup or the amount of those markups (table 12). A review of the data reveals the reason why this outcome occurs. The amount of uncommitted fringe generation in western Colorado and Wyoming is sufficient to congest the transmission paths less than 5% of a year.

Table 12.

Scenario 2 Summary

	2002	2003	2004	2005
Competitive market share	87%	87%	85%	85%
Base case market share with price markup	53%	54%	50%	51%
Scenario 2 market share with price markup	53%	54%	50%	51%
Base case % of year markup applied	93%	95%	94%	96%
Scenario 2 % of year markup applied	93%	95%	94%	96%
Elasticity	Average Markup			
0.9	53%	55%	50%	52%
0.7	68%	71%	65%	67%
0.4	120%	124%	113%	117%
0.1	478%	498%	452%	468%
Elasticity	Average Price			
0.9	$21.90	$25.16	$27.34	$31.45
0.7	$24.07	$27.72	$29.95	$34.53
0.4	$31.39	$36.36	$38.75	$44.90
0.1	$82.66	$96.83	$100.42	$117.48

This does not mean that the transmission constraints do not play a significant role in RMPA's power flows. Rather, the result is more a statement about the limited amount of uncommitted fringe generation within the RMPA. The total rated transmission import capacity into eastern Colorado is 3,104 MW. The total generation capacity in western Colorado and Wyoming is 4,348 MW. Given that the model assumes that generation resident in a particular area serves its native load first, there just is not enough generation left over, once native demand is served by fringe firms in western Colorado and Wyoming, to make the transmission constraints much of a factor.

It appears that transmission constraints would become important only if generation from beyond the boundaries of the RMPA attempted to enter the eastern Colorado market. This eventuality is not modeled in this scenario because of the declining reserve margins in the WSCC (table 5). Additionally, excess WSCC generation beyond the RMPA may be drawn to California, Nevada, or Arizona, all of which are implementing electric restructuring on a timetable faster than Colorado and currently have higher energy prices.

Entry of 1,000 MW of Fringe Generation

The entry of new fringe generation appears to have a limited, but negative effect upon PSCo's ability to exercise market power (figure 36). The period of the year over which PSCo could apply a price markup falls from 93% to not more than 79% during the years 2002-2005. The difference between price and marginal cost for these markups is reduced similarly. Entry reduces the markup that can be applied because the quantity of fringe generation in the market place is greater. When the term

$$\text{PSCo Market Share} = \frac{q_{PSCo} - q_{f\_E.Co} - q_{f\_W.Co} - q_{f\_Wyo}}{Q_{Market}} \tag{7.1}$$

is calculated, $q_{f\_E.Co}$ is larger in this scenario. Therefore, the sum of the three fringe quantities ($q_{f\_E.Co} + q_{f\_W.Co} + q_{f\_Wyo}$) available to enter the market is greater than or equal to PSCo's competitive market quantity supplied (q_{PSCo}) for a larger portion of the year. When PSCo's competitive market supply is greater than the available fringe capacity, PSCo's residual demand ($q_{PSCo} - q_{f\_E.Co} - q_{f\_W.Co} - q_{f\_Wyo}$) is lower, resulting in a lower markup.

Key to this result is the assumption that the 1,000 MW of generation becomes part of the competitive fringe. If all 1,000 MW were controlled by one or two firms, these new

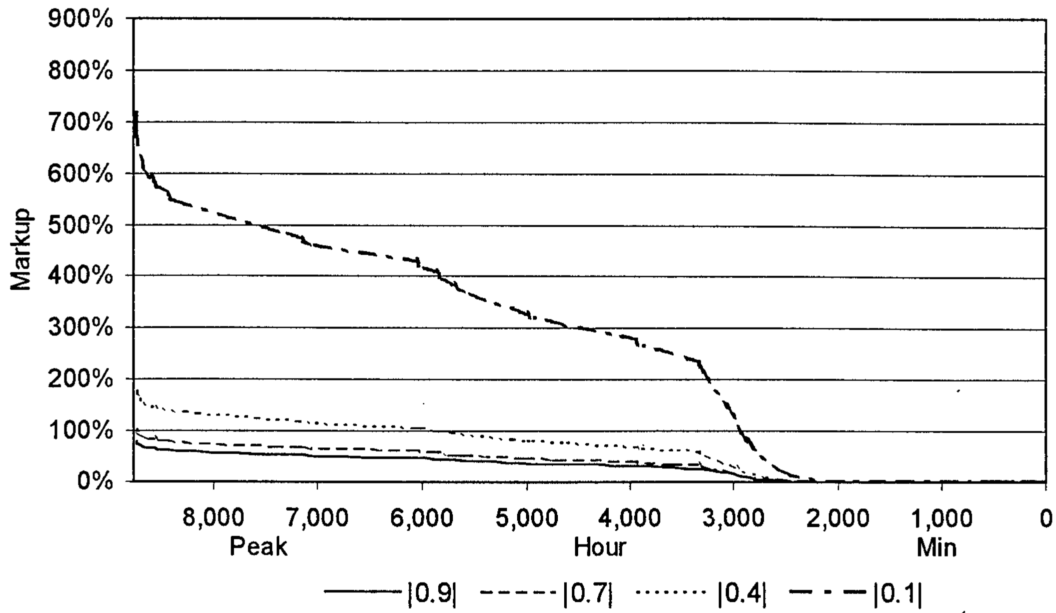


Figure 36. Markups PSCo can apply over marginal cost given a range of price elasticities of demand in 2002, assuming that 1,000 MW of fringe generation is built in eastern Colorado by 2002.

firms may attempt to exert market power. With two or more firms attempting to exert market power, the restructured Colorado electricity market could evolve into Cournot competition. The problem of price markups would remain, although in general, markups under Cournot competition are lower than markups by a single, dominant firm.

Additionally, once some entry occurs, the threat of continued entry might discipline PSCo's pricing behavior. Baumol's theory of contestable markets, described in the

literature review is the basis for this hope. A small degree of entry by generation firms into the eastern Colorado market could be evidence to PSCo that there are more firms with capital who are seeking profit opportunities. Pricing above marginal generation cost might not, therefore, be in PSCo's best interest in the long run because it might motivate other firms to enter the eastern Colorado generation market. On the other hand, PSCo could adopt a strategy of giving up market share in eastern Colorado in return for the opportunity to sell its generation elsewhere on the grid in more lucrative markets. Additionally, entry by new firms may provide PSCo the opportunity to retire some of its older, less-efficient plants. This was the response of generation firm's in the UK as new firms entered the market (Newbery 1995, 53).

Under this scenario, PSCo is able to exercise market power only at the expense of losing a large share of the generation market (table 13). It seems doubtful that transmission capacity would permit PSCo to sell all of the generation idled by pursuing a policy of applying maximum price markups elsewhere on the Western Interconnect. This could result in even lower price markups.

Table 13.

Scenario 3 Summary

	2002	2003	2004	2005
Competitive market share assuming entry	87%	87%	85%	85%
Base case market share with price markup	53%	54%	50%	51%
Scenario 3 market share with price markup	47%	45%	43%	42%
Base case % of year markup applied	93%	95%	94%	96%
Scenario 3 % of year markup applied	78%	74%	77%	79%
Elasticity	Average Markup			
0.9	31%	35%	27%	28%
0.7	39%	45%	34%	36%
0.4	69%	79%	60%	63%
0.1	276%	314%	240%	252%
Elasticity	Average Price			
0.9	$18.68	$21.86	$23.06	$26.49
0.7	$19.94	$23.48	$24.45	$28.14
0.4	$24.17	$28.93	$29.14	$33.73
0.1	$53.76	$67.14	$61.96	$72.81

PSCo's Divestiture of 50% of Its Generation

Under this scenario, half of each generation resource PSCo owns is divested to the competitive fringe, including plants, contracts with other utilities, and contracts with independent power producers. The total divestiture is approximately 2,500 MW. While the way this approach is implemented in the model is admittedly unrealistic, the model was formulated in the manner to avoid skewing the

outcome that might result if PSCo divested only its baseload plants, only its peaking plants, or some other combination that altered the balance of its generation portfolio. If divestiture is implemented, policy makers might want to consider the specifics of which plants are divested in their calculation of market effects.

The amount of time PSCo can apply a markup over marginal cost is reduced from 93% in the base case to not more than 47% for 2002-2005 (figure 37). The average markup

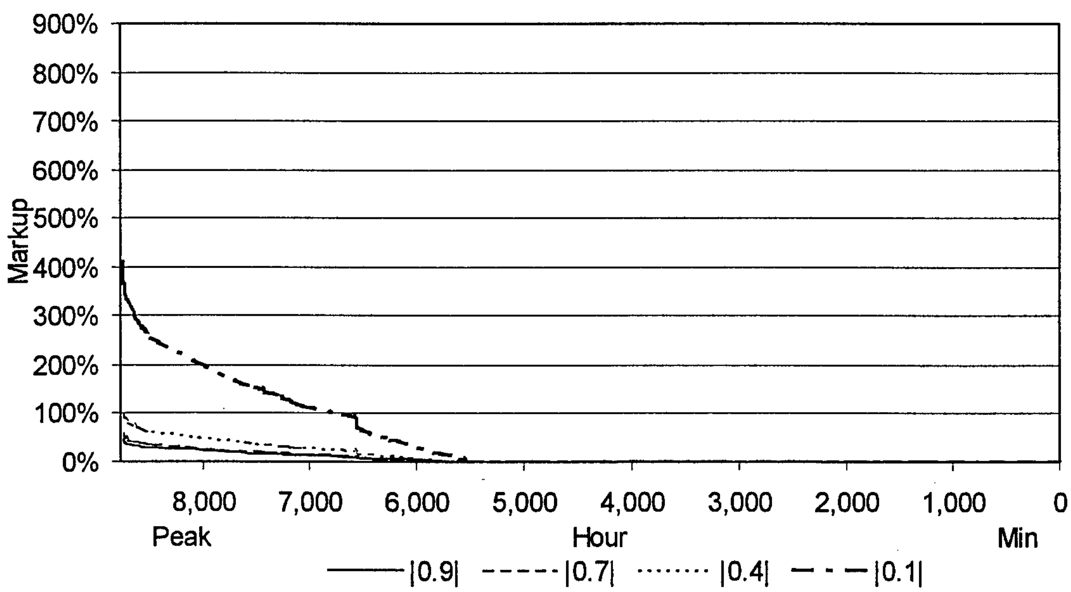


Figure 37. Markups PSCo can apply over marginal cost given a range of price elasticities of demand in 2002, assuming PSCo divests 50% of its generation to fringe firms.

is approximately one-eighth the markup of the base case. Attempting to exercise market power comes at a loss of market share also (table 14). It is questionable whether PSCo would really profit by forgoing this much eastern Colorado market share in return for the opportunity to sell its power elsewhere.

Table 14.

Scenario 4 Summary

	2002	2003	2004	2005
Competitive market share assuming divestiture	44%	44%	42%	43%
Base case market share with price markup	53%	54%	50%	51%
Scenario 4 market share with price markup	33%	30%	29%	29%
Base case % of year markup applied	93%	95%	94%	96%
Scenario 4 % of year markup applied	37%	47%	44%	45%
Elasticity	Average Markup			
0.9	6%	7%	6%	7%
0.7	8%	10%	8%	9%
0.4	14%	17%	14%	15%
0.1	56%	67%	56%	61%
Elasticity	Average Price			
0.9	$15.19	$17.41	$19.33	$22.11
0.7	$15.45	$17.75	$19.66	$22.52
0.4	$16.31	$18.91	$20.75	$23.88
0.1	$22.33	$27.05	$28.40	$33.41

The limited degree of market power portrayed in this scenario may even have a socially beneficial consequence. If prices are at marginal cost most of the year, and only diverge from marginal cost during periods of peak demand, consumers might be motivated to conserve or shift load to off-peak periods. This could have long-term social benefits by reducing the need for new generation, reducing society's consumption of fossil fuels, and limiting pollutants released into the atmosphere.

Comparison of Scenarios

When the outcome of each scenario is compared, the similarities and differences become obvious (figure 38). There is almost no difference in the extent and duration of price markups that can be applied in the base case and when RMPA transmission constraints are relaxed. The entry of 1,000 MW of fringe generation reduces the extent and duration of markups. The divestiture of 50% of its generation appears to be most effective means to reduce PSCo's ability to apply a markup over marginal cost. PSCo can apply a markup over only a small portion of the year. The amount of markup is approximately one-eighth the base case.

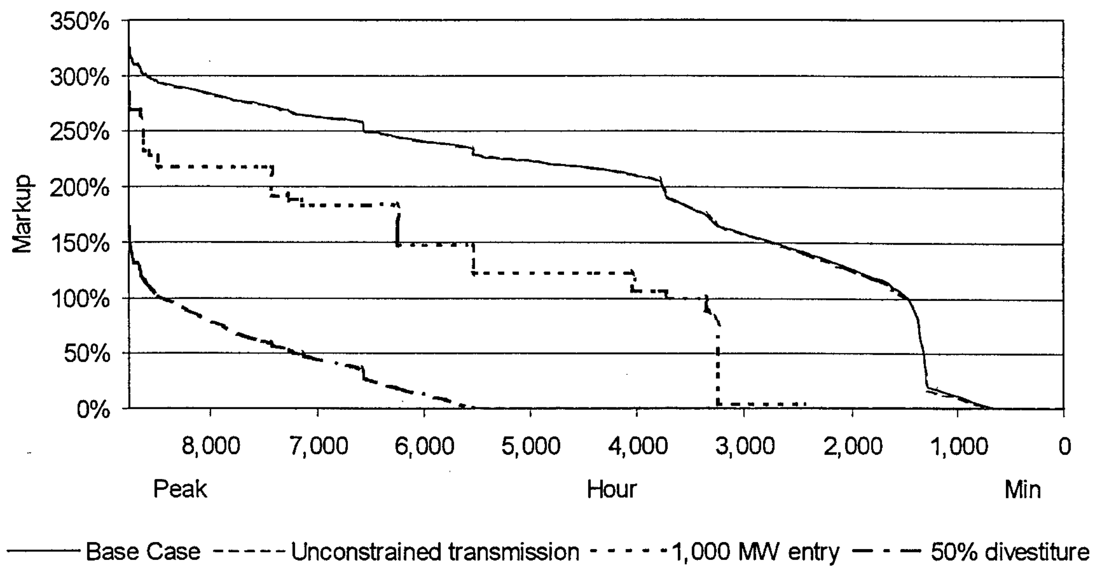


Figure 38. Comparison of markups PSCo can apply over marginal cost to various customer classes in 2002 in each scenario, elasticity = |0.4|.

The other result readily apparent from all scenarios is that the price elasticity of demand plays a large difference in the calculation of markups. Policy makers might want to consider measures that protect smaller consumers as well as measures that promote the elasticity of demand for all customer classes. The effectiveness of measures such as real-time pricing to affect demand elasticity has not been proven by any study. Anecdotal evidence from Colorado utilities that have implemented pilot programs offering real

time pricing has shown that most customers do not participate in these programs (Allum 1997).

Furthermore, the contrast in the results of this study over the elasticity range must be considered in light of the fact that some studies, notably those by the Energy Information Administration (1997c, 24), assume the range of demand elasticity to be $|0.15| - |0.5|$. If this range of elasticities was assumed, overall markups would be greater.

Chapter 8

POLICY IMPLICATIONS AND ISSUES FOR FURTHER ANALYSIS

This study represents an initial effort at quantifying the effects of the market power of a dominant firm in a restructured electricity market. Although the analysis is tied to the specifics of generation and transmission pertinent to Colorado, its framework may have value to the other 31 states where one firm controls a significant portion of the state's generation. The economic paradigm of a dominant firm that acts as a "price maker," and a competitive fringe that are "price takers," would only be suitable when one firm controls a large market share, and all other firms are so small that they must be considered part of the competitive fringe. If there are multiple firms, each with a large share of the market, a Cournot model may be more appropriate. The Cournot model is detailed in analyses by Newbery (1995), Borenstein and Bushnell (1997), Klemperer and Meyer (1989), and others.

What size market share must a dominant firm own to cause concern? There is no clear rule. As part of his screens for market power, Joskow (1995, 8) sets a threshold

market share of 35% for the dominant firm. Furthermore, in generation markets, defining the relevant market as a basis to estimate market share is not an easy task. One could begin by analyzing the transmission network relevant to a particular area. If transmission into a particular area is frequently constrained, one could then analyze the market shares of firms within that particular geographic area, together with the market shares of firms outside that area, that compete up to the level of transmission constraints. During periods where transmission paths aren't constrained, it may be more germane to consider the entry capability of firms over a wider geographic area. For all fringe firms, capacity by itself might not necessarily be important. Instead, it might be more appropriate to consider the excess capacity firms own, once their native load is served.

In the case of Colorado, these requirements were facilitated by the fact that eastern Colorado, which would comprise most of Colorado's restructured electricity market, sits at the eastern edge of the Western Interconnect. The only two paths into this region are from Wyoming and western Colorado and these are frequently constrained. Beyond western Colorado and Wyoming, little power flows from the rest of the WSCC into eastern Colorado. The role of the

Northwest Power Pool and Arizona-New Mexico regions could, therefore, be assumed to be very limited. The declining reserve margins in these regions reinforces this assumption. Transmission analysis becomes much more complicated as the number of transmission paths increase.

Once the relevant geographic market is defined, the Herfindahl-Hirshman Index remains a useful screening tool. The guideline Joskow (1995, 35) proposes is that if the HHI is below 2,500, the market is probably reasonably competitive. Markets with an HHI above this benchmark merit further investigation.

The HHI for the eastern Colorado generation market is approximately 5,000 when transmission is congested, which reflects PSCo's ownership or control through contracts of 75% of the eastern Colorado generation. If the relevant market is the entire RMPA, the HHI is 3,000. In either case, the HHI suggests a strong possibility that the market power PSCo could exercise in a restructured Colorado electricity market might be a concern.

This study confirms the possibility of market power suggested by the HHI. The dominant firm, PSCo, has the market power to apply very large markups over most of the year. However, there is no claim that PSCo would actually

apply the markups calculated. Such pricing behavior would inevitably create a backlash that would be to the detriment of the company in the long run. There would be calls for re-regulation, new firms would enter the market, and customers would be more inclined to switch suppliers. Rather the calculated markups and their duration are an indicator of the dominant firm's large degree of market power.

The more important conclusion that can be drawn from this analysis is that there is no guarantee that electric restructuring would force prices to marginal cost in a state with a dominant firm. This outcome, in itself, is significant for any ex ante calculation of the benefits of electric restructuring or stranded costs. Estimates of electric restructuring benefits should probably incorporate a sensitivity analysis that portray a range of markups over marginal cost. Since it is impossible to calculate stranded costs without some estimate of market prices, stranded cost calculations should also probably include a sensitivity analysis for price variations.

Furthermore, states developing electric restructuring plans where one firm controls a large share of the market might want to carefully consider measures that mitigate

market power. This could be done through measures that create appropriate market structures, reduce the dominant firm's market share, and increase the price elasticity of demand of consumers. It is probably not necessary to eliminate the dominant firm's market power at all times. Policy makers instead may be comfortable with the assurance that competitive pricing will prevail "most" of the time (and these policy makers must determine what level of "most" they are comfortable with).

In terms of appropriate market structures to mitigate market power, there are numerous policy options, including Poolco's, Independent System Operators, transmission pricing schemes, and market aggregators. An adequate description of each of these options is beyond the scope of this analysis. Policy makers can develop state restructuring plans that employ these measures singly or in combination to mitigate market power.

Reducing the dominant firm's market share would be implemented most easily if the company simply voluntarily agreed to divest a portion of its generation in return for the opportunity to compete for unregulated profits or for favorable consideration of its estimate of stranded costs. If a voluntary agreement between the state and the firm

cannot be reached, the task of reducing the dominant firm's market share is much more difficult. The restructuring plan could include measures to make it easier for new generation firms to enter the market, but these measures may conflict with the need to hold entrants to high standards that promote reliability. Power marketers can also play a role in increasing competition by buying excess power anywhere on the grid and reselling it. The restructuring plan may include provisions for how power marketers enter the market and what standards, if any, they are held to. While increasing transmission capacity is another option, the time, capital investment, and uncertainty associated with the availability of excess generation elsewhere make this option a risky proposition.

Finally, measures to increase consumer's price elasticity of demand are touted by economists as an effective means of mitigating market power, but their acceptance by customers, particularly small customers has not been demonstrated. Relatively few loads in a regulated environment are interruptible. It was only during the oil shocks of the 1970s that small customers made any large-scale efforts at conservation of electricity, or substitution to alternatives, such as solar energy. Real-

time metering and pricing of electricity has already been incorporated in some state restructuring plans. The implicit assumption of real-time pricing is that if customers see how their electric rates vary with overall demand, they may be more inclined to reduce consumption during peak periods.

As stated earlier, this analysis represents only an initial effort at quantifying a dominant firm's market power. The analysis has already admitted its shortcomings in the way the shape of the load curve is assumed to be the same for the entire RMPA, when this is clearly not true. There are other ways the analysis can be refined and improved.

The utilities considered in this study could improve the analysis by reviewing and updating the plant level cost and capacity data required to run the Elfin simulation. While much of this data is publicly available, there are some gaps, where the cost and capacity of particular plants had to be estimated from similar plants. Furthermore, any utility knowledge of how these costs are expected to change in the future would be invaluable. The model currently relies on historical costs, and assumes any changes, such as fluctuations in fuel prices, would affect all firms equally.

Utilities may be unwilling to provide this information; however they might agree to do so if they were assured that their data would remain confidential. This might require that model output be aggregated to some level that masks plant specific characteristics.

A new version of Elfin currently being beta-tested enables the modeling of up to ten markets simultaneously. The six control areas of the RMPA could then each be modeled with its own load curve and resident generation. The Northwest Power Pool, Arizona-New Mexico, and Eastern Interconnect, via the DC ties, could be modeled as separate markets. This might result in a simulation that has higher fidelity to reality.

The modeling of other scenarios might also reveal additional insights. A complex, and dynamic problem might be to model how the dominant firm can withhold a certain quantity of generation from the eastern Colorado market, driving up price and encouraging entry by the competitive fringe, while the dominant firm exports its excess generation to other restructured markets. This analysis would require a detailed study of the available transmission capacity over which power would move to these distant markets.

Additional scenarios will be appropriate as specific market structures are developed by state policy makers. There are many options in this regard over which the current study was intentionally vague. For instance, would a restructured state market be part of a larger, regional Independent System Operator (IndeGo, Desert STAR)? Would the market include long-term bi-lateral contracts as well as a short-term commodity market (Poolco)? What are the pricing effects of social benefits charges and stranded cost recovery? The answers to each of these questions will each drive changes to the model and its output. These issues could keep consultants and academics employed for many years.

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APPENDIX A

Rocky Mountain Power Generation

Year	Company	Plant	Cap (MW)	Cost ($/MWh) Fuel	O&M	Total	Shared	Data Source
2002	ARPA	Lamar 3,4	3	50	0.2	50.2		Estimate
2002	ARPA	Lamar 6	25	20.4	1.2	21.6		Estimate
2002	ARPA	Trinidad 4	3	15	1.6	16.6		Estimate
2002	Basin Electric	Laramie River	702	5.4	1	6.4	Note 1	RDI
2002	Black Hills	Ben French GT	68	28.9	0.1	29		RDI
2002	Black Hills	Ben French IC	10	50	0.2	50.2		RDI
2002	Black Hills	Ben French ST	22	15	1.6	16.6		RDI
2002	Black Hills	Neil Simpson 1, 2	98	8.5	0.5	9		RDI
2002	Black Hills	Osage	30	14.3	0.1	14.4		RDI
2002	CO Springs	Drake	267	19.6	0.9	20.4		EIA-412
2002	CO Springs	George Birdsall	57	50	0.3	50.3		EIA-412
2002	CO Springs	Manitou	2	0	0	0		EIA-412
2002	CO Springs	Nixon	207	10.4	0.9	11.3		EIA-412
2002	CO Springs	Nixon CT 2	68	50	0	50		EIA-412
2002	CO Springs	Nixon CT1	68	50	0	50		EIA-412
2002	CO Springs	Ruxton	0	0	0	0		EIA-412
2002	CO Springs	Tesla 1	25	0	0	0		EIA-412
2002	IPPs	American Atlas	81	50	0	50		Estimate
2002	IPPs	Biogas 1 - IPP	4	10	0	10		Estimate
2002	IPPs	E Co IPP Hydro	6	0	0	0		Estimate
2002	IPPs	Ignacio Gas - IPP	6	50	0	50		Estimate
2002	IPPs	Wattenburg Field	1	50	0	50		Estimate
2002	MEAN	Ruedi	4	0	0	0		RDI
2002	PRPA	Rawhide	150	8.1	1.3	9.4		RDI
2002	PSCo	75th St Waste Water	1	12.8	0	12.8		PUC Staff
2002	PSCo	Alamosa	36	50	0	50		FERC Form 1
2002	PSCo	American Atlas	81	12.8	0	12.8		PUC Staff
2002	PSCo	Arapahoe	246	14	0.6	14.6		FERC Form 1
2002	PSCo	Boulder	20	0.2	0	0.2		RDI
2002	PSCo	Cabin Creek	215		0.6	0.6		RDI
2002	PSCo	Cameo	73	9	0.7	9.7		FERC Form 1
2002	PSCo	Cherokee	723	11	0.5	11.5		FERC Form 1
2002	PSCo	CO Power Proj 1	50	12.8	0	12.9		PUC Staff
2002	PSCo	CO Power Proj 2	68	12.8	0	12.9		PUC Staff
2002	PSCo	Comanche	660	10.1	0.4	10.5		FERC Form 1
2002	PSCo	Coors Biotech	3	12.8	0	12.9		PUC Staff

Year	Company	Plant	Cap (MW)	Cost ($/MWh) Fuel	O&M	Total	Shared	Data Source
2002	PSCo	County Line Landfill	1	12.8	0	12.9		PUC Staff
2002	PSCo	Craig	1264	10	0.7	10.7	Note 2	FERC Form 1
2002	PSCo	Fort Lupton	92	38	0	38		FERC Form 1
2002	PSCo	Fruita	17	50	0.1	50.1		FERC Form 1
2002	PSCo	Ft. Lupton Cogen	150	12.8	0	12.8		PUC Staff
2002	PSCo	Ft. St. Vrain	475	29	0	29		FERC Form 1
2002	PSCo	Generic CT	104	29	0	29		Estimate
2002	PSCo	Generic CT	104	29	0	29		Estimate
2002	PSCo	Greeley Energy 1	68	12.8	0	12.9		PUC Staff
2002	PSCo	Hayden	446	12	0.5	12.5	Note 3	FERC Form 1
2002	PSCo	Hillcrest 1	2	0	12.8	12.8		PUC Staff
2002	PSCo	LRS/TSGT contract	200	15	0	15		RDI
2002	PSCo	Monfort	32	12.9	0	12.9		PUC Staff
2002	PSCo	Mount Elbert PS	200		0.1	0.1		RDI
2002	PSCo	Pawnee	511	9	0.5	9.5		FERC Form 1
2002	PSCo	PSCO E Co Hydro	8	0	12.9	12.9		PUC Staff
2002	PSCo	PSCO W CO Small Hydro	25	0	1.1	1.1		Estimate
2002	PSCo	Rawhide - PSCo	112	17.6	0	17.6		RDI
2002	PSCo	Shoshone	14	0.3	0	0.3		FERC Form 1
2002	PSCo	Tacoma	9	0	0	0		FERC Form 1
2002	PSCo	Total Cogeneration	19	12.8	0	12.8		PUC Staff
2002	PSCo	U of CO Cogen	10	12.9	0	12.8		PUC Staff
2002	PSCo	Valmont GT	53	37	0	37		FERC Form 1
2002	PSCo	Valmont ST	189	13	0.5	13.5		FERC Form 1
2002	PSCo	West Power 1	122	12.8	0	12.8		PUC Staff
2002	PSCo	Windsource	4	20	0	20		Estimate
2002	PSCo	Zuni	107	47.4	0.3	47.7		FERC Form 1
2002	Tri-State	Burlington	100	50	0.2	50.2		RDI
2002	Tri-State	Delta 1	1	50	0	50		Estimate
2002	Tri-State	Delta 5	1	50	0	50		Estimate
2002	Tri-State	Delta 7	2	50	0	50		Estimate
2002	Tri-State	Laramie River	198	5.4	1	6.4		Ann Report
2002	Tri-State	Nucla	100	9.5	24.6	34.1		Ann Report
2002	WAPA	WAPA LAP E CO	198	0	10.8	10.8		RDI
2002	WAPA	WAPA LAP W CO	26	0	10.9	10.9		RDI
2002	WAPA	WAPA LAP WY	394	0	10.9	10.9		RDI
2002	WAPA	WAPA Salt Lake	310	0	8.9	8.9		RDI
2002	WestPlains	Clark	43	15.7	2.7	18.4		FERC Form 1
2002	WestPlains	Pueblo IC	10	38.8	0	38.8		FERC Form 1
2002	WestPlains	Pueblo ST	19	60.5	1	61.5		FERC Form 1
2002	WestPlains	Rocky Ford	10	64.7	0.1	64.8		FERC Form 1
2002	WestPlains	WestPlains 1st add	45	29	0	29		FERC Form 1

Year	Company	Plant	Cap (MW)	Cost ($/MWh) Fuel	O&M	Total	Shared	Data Source
2002	WestPlains	WestPlains 2nd add	5	29	0	29		FERC Form 1
2002	WestPlains	WestPlains 3rd add	10	29	0	29		FERC Form 1
2002	WestPlains	WestPlains 4th add	5	29	0	29		FERC Form 1
2002	WestPlains	WestPlains 5th add	195	29	0	29		FERC Form 1
2003	ARPA	Lamar 3,4	3	50	0.2	50.2		Estimate
2003	ARPA	Lamar 6	25	20.4	1.2	21.6		Estimate
2003	ARPA	Trinidad 4	3	15	1.6	16.6		Estimate
2003	Basin Electric	Laramie River	702	5.4	1	6.4	Note 1	RDI
2003	Black Hills	Ben French GT	68	28.9	0.1	29		RDI
2003	Black Hills	Ben French IC	10	50	0.2	50.2		RDI
2003	Black Hills	Ben French ST	22	15	1.6	16.6		RDI
2003	Black Hills	Neil Simpson 1, 2	98	8.5	0.5	9		RDI
2003	Black Hills	Osage	30	14.3	0.1	14.4		RDI
2003	CO Springs	Drake	267	19.6	0.9	20.4		EIA-412
2003	CO Springs	George Birdsall	57	50	0.3	50.3		EIA-412
2003	CO Springs	Manitou	2	0	0	0		EIA-412
2003	CO Springs	Nixon	207	10.4	0.9	11.3		EIA-412
2003	CO Springs	Nixon CT 2	68	50	0	50		EIA-412
2003	CO Springs	Nixon CT1	68	50	0	50		EIA-412
2003	CO Springs	Ruxton	0	0	0	0		EIA-412
2003	CO Springs	Tesla 1	25	0	0	0		EIA-412
2003	IPPs	American Atlas	81	50	0	50		Estimate
2003	IPPs	Biogas 1 - IPP	4	10	0	10		Estimate
2003	IPPs	E Co IPP Hydro	8	0	0	0		Estimate
2003	IPPs	Ignacio Gas - IPP	6	50	0	50		Estimate
2003	IPPs	Wattenburg Field	1	50	0	50		Estimate
2003	MEAN	Ruedi	4	0	0	0		RDI
2003	PRPA	Rawhide	163	8.1	1.3	9.4		RDI
2003	PSCo	75th St Waste Water	1	12.8	0	12.8		PUC Staff
2003	PSCo	Alamosa	36	50	0	50		FERC Form 1
2003	PSCo	American Atlas	81	12.8	0	12.8		PUC Staff
2003	PSCo	Arapahoe	246	14	0.6	14.6		FERC Form 1
2003	PSCo	Boulder	20	0.2	0	0.2		RDI
2003	PSCo	Cabin Creek	215		0.6	0.6		RDI
2003	PSCo	Cameo	73	9	0.7	9.7		FERC Form 1
2003	PSCo	Cherokee	723	11	0.5	11.5		FERC Form 1
2003	PSCo	CO Power Proj 1	50	12.8	0	12.8		PUC Staff
2003	PSCo	CO Power Proj 2	68	12.9	0	12.9		PUC Staff
2003	PSCo	Comanche	660	10.1	0.4	10.5		FERC Form 1
2003	PSCo	Coors Biotech	3	12.8	0	12.8		PUC Staff
2003	PSCo	County Line Landfill	1	12.9	0	12.8		PUC Staff
2003	PSCo	Craig	1264	10	0.7	10.7	Note 2	FERC Form 1

Year	Company	Plant	Cap (MW)	Cost ($/MWh) Fuel	O&M	Total	Shared	Data Source
2003	PSCo	Fort Lupton	92	38	0	38		FERC Form 1
2003	PSCo	Fruita	17	50	0.1	50.1		FERC Form 1
2003	PSCo	Ft. Lupton Cogen	150	12.8	0	12.8		PUC Staff
2003	PSCo	Ft. St. Vrain	475	29	0	29		FERC Form 1
2003	PSCo	Generic CT	104	29	0	29		Estimate
2003	PSCo	Generic CT	104	29	0	29		Estimate
2003	PSCo	Generic CT	181	29	0	29		Estimate
2003	PSCo	Greeley Energy 1	68	12.8	0	12.9		PUC Staff
2003	PSCo	Hayden	446	12	0.5	12.5		FERC Form 1
2003	PSCo	Hillcrest 1	2	0	12.9	12.9		PUC Staff
2003	PSCo	Monfort	32	12.9	0	12.8		PUC Staff
2003	PSCo	Mount Elbert PS	200		0.1	0.1		RDI
2003	PSCo	Pawnee	511	9	0.5	9.5		FERC Form 1
2003	PSCo	PSCO E Co Hydro	6	0	12.8	12.8		PUC Staff
2003	PSCo	PSCO W CO Small Hydro	25	0	1.1	1.1		Estimate
2003	PSCo	Rawhide - PSCo	99	17.6	0	17.6		RDI
2003	PSCo	Shoshone	14	0.3	0	0.3		FERC Form 1
2003	PSCo	Tacoma	9	0	0	0		FERC Form 1
2003	PSCo	Total Cogeneration	19	12.9	0	12.9		PUC Staff
2003	PSCo	U of CO Cogen	10	12.9	0	12.9		PUC Staff
2003	PSCo	Valmont GT	53	37	0	37		FERC Form 1
2003	PSCo	Valmont ST	189	13	0.5	13.5		FERC Form 1
2003	PSCo	West Power 1	122	12.8	0	12.8		PUC Staff
2003	PSCo	Windsource	4	20	0	20		Estimate
2003	PSCo	Zuni	107	47.3	0.3	47.7		FERC Form 1
2003	Tri-State	Burlington	100	50	0.2	50.2		RDI
2003	Tri-State	Delta 1	1	50	0	50		Estimate
2003	Tri-State	Delta 5	1	50	0	50		Estimate
2003	Tri-State	Delta 7	2	50	0	50		Estimate
2003	Tri-State	Laramie River	398	5.4	1	6.4		Ann Report
2003	Tri-State	Nucla	100	9.5	24.6	34.1		Ann Report
2003	WAPA	WAPA LAP E CO	198	0	10.8	10.8		RDI
2003	WAPA	WAPA LAP W CO	26	0	10.9	10.9		RDI
2003	WAPA	WAPA LAP WY	394	0	10.9	10.9		RDI
2003	WAPA	WAPA Salt Lake	310	0	8.9	8.9		RDI
2003	WestPlains	Clark	43	15.7	2.7	18.4		FERC Form 1
2003	WestPlains	Pueblo IC	10	38.8	0	38.8		FERC Form 1
2003	WestPlains	Pueblo ST	19	60.5	1	61.5		FERC Form 1
2003	WestPlains	Rocky Ford	10	64.7	0.1	64.8		FERC Form 1
2003	WestPlains	WestPlains 1st add	45	29	0	29		FERC Form 1
2003	WestPlains	WestPlains 2nd add	5	29	0	29		FERC Form 1
2003	WestPlains	WestPlains 3rd add	10	29	0	29		FERC Form 1

Year	Company	Plant	Cap (MW)	Cost ($/MWh) Fuel	O&M	Total	Shared	Data Source
2003	WestPlains	WestPlains 4th add	5	29	0	29		FERC Form 1
2003	WestPlains	WestPlains 5th add	195	29	0	29		FERC Form 1
2004	ARPA	Lamar 3,4	3	50	0.2	50.2		Estimate
2004	ARPA	Lamar 6	25	20.4	1.2	21.6		Estimate
2004	ARPA	Trinidad 4	3	15	1.6	16.6		Estimate
2004	Basin Electric	Laramie River	702	5.4	1	6.4	Note 1	RDI
2004	Black Hills	Ben French GT	68	28.9	0.1	29		RDI
2004	Black Hills	Ben French IC	10	50	0.2	50.2		RDI
2004	Black Hills	Ben French ST	22	15	1.6	16.6		RDI
2004	Black Hills	Neil Simpson 1, 2	98	8.5	0.5	9		RDI
2004	Black Hills	Osage	30	14.3	0.1	14.4		RDI
2004	CO Springs	Drake	267	19.6	0.9	20.4		EIA-412
2004	CO Springs	George Birdsall	57	50	0.3	50.3		EIA-412
2004	CO Springs	Manitou	2	0	0	0		EIA-412
2004	CO Springs	Nixon	207	10.4	0.9	11.3		EIA-412
2004	CO Springs	Nixon CT 2	68	50	0	50		EIA-412
2004	CO Springs	Nixon CT1	68	50	0	50		EIA-412
2004	CO Springs	Ruxton	0	0	0	0		EIA-412
2004	CO Springs	Tesla 1	25	0	0	0		EIA-412
2004	IPPs	American Atlas	81	50	0	50		Estimate
2004	IPPs	Biogas 1 - IPP	4	10	0	10		Estimate
2004	IPPs	E Co IPP Hydro	14	0	0.1	0.1		Estimate
2004	IPPs	Greely Energy 1	68	50	0	50		Estimate
2004	IPPs	Ignacio Gas - IPP	6	50	0	50		Estimate
2004	IPPs	Wattenburg Field	1	50	0	50		Estimate
2004	MEAN	Ruedi	4	0	0	0		RDI
2004	PRPA	Rawhide	262	8.2	1.3	9.5		RDI
2004	PSCo	75th St Waste Water	1	12.8	0	12.8		PUC Staff
2004	PSCo	Alamosa	36	50	0	50		FERC Form 1
2004	PSCo	American Atlas	81	12.9	0	12.8		PUC Staff
2004	PSCo	Arapahoe	246	14	0.6	14.6		FERC Form 1
2004	PSCo	Boulder	20	0.2	0	0.2		RDI
2004	PSCo	Cabin Creek	215		0.7	0.7		RDI
2004	PSCo	Cameo	73	9	0.7	9.7		FERC Form 1
2004	PSCo	Cherokee	723	11	0.5	11.5		FERC Form 1
2004	PSCo	CO Power Proj 1	50	12.9	0	12.9		PUC Staff
2004	PSCo	CO Power Proj 2	68	12.9	0	12.9		PUC Staff
2004	PSCo	Comanche	660	10.1	0.4	10.5		FERC Form 1
2004	PSCo	Coors Biotech	3	12.9	0	12.9		PUC Staff
2004	PSCo	County Line Landfill	1	12.9	0	12.8		PUC Staff
2004	PSCo	Craig	1264	10	0.7	10.7	Note 2	FERC Form 1
2004	PSCo	Fort Lupton	92	38	0	38		FERC Form 1

Year	Company	Plant	Cap (MW)	Cost ($/MWh) Fuel	O&M	Total	Shared	Data Source
2004	PSCo	Fruita	17	50	0.1	50.1		FERC Form 1
2004	PSCo	Ft. Lupton Cogen	150	12.8	0	12.8		PUC Staff
2004	PSCo	Ft. St. Vrain	475	29	0	29		FERC Form 1
2004	PSCo	Generic CT	104	29	0	29		Estimate
2004	PSCo	Generic CT	104	29	0	29		Estimate
2004	PSCo	Generic CT	181	29	0	29		Estimate
2004	PSCo	Generic CT	104	29	0	29		Estimate
2004	PSCo	Generic CT	181	29	0	29		Estimate
2004	PSCo	Hayden	446	12	0.5	12.5		FERC Form 1
2004	PSCo	Hillcrest 1	2	0	12.8	12.8		PUC Staff
2004	PSCo	Monfort	32	12.9	0	12.9		PUC Staff
2004	PSCo	Mount Elbert PS	200		0.1	0.1		RDI
2004	PSCo	Pawnee	511	9	0.5	9.5		FERC Form 1
2004	PSCo	PSCO W CO Small Hydro	25	0	1.1	1.1		Estimate
2004	PSCo	Rawhide - PSCo	0	17.6	0	17.6		RDI
2004	PSCo	Shoshone	14	0.3	0	0.3		FERC Form 1
2004	PSCo	Tacoma	9	0	0	0		FERC Form 1
2004	PSCo	Total Cogeneration	19	12.8	0	12.8		PUC Staff
2004	PSCo	U of CO Cogen	10	12.8	0	12.8		PUC Staff
2004	PSCo	Valmont GT	53	37	0	37		FERC Form 1
2004	PSCo	Valmont ST	189	13	0.5	13.5		FERC Form 1
2004	PSCo	West Power 1	122	12.9	0	12.9		PUC Staff
2004	PSCo	Windsource	4	20	0	20		Estimate
2004	PSCo	Zuni	107	47.3	0.3	47.7		FERC Form 1
2004	Tri-State	Burlington	100	50	0.2	50.2		RDI
2004	Tri-State	Delta 1	1	50	0	50		Estimate
2004	Tri-State	Delta 5	1	50	0	50		Estimate
2004	Tri-State	Delta 7	2	50	0	50		Estimate
2004	Tri-State	Laramie River	398	5.4	1	6.4		Ann Report
2004	Tri-State	Nucla	100	9.5	24.6	34.1		Ann Report
2004	WAPA	WAPA LAP E CO	198	0	10.9	10.9		RDI
2004	WAPA	WAPA LAP W CO	26	0	10.8	10.8		RDI
2004	WAPA	WAPA LAP WY	394	0	10.8	10.8		RDI
2004	WAPA	WAPA Salt Lake	310	0	8.9	8.9		RDI
2004	WestPlains	Clark	43	15.7	2.7	18.4		FERC Form 1
2004	WestPlains	Pueblo IC	10	38.8	0	38.8		FERC Form 1
2004	WestPlains	Pueblo ST	19	60.5	1	61.5		FERC Form 1
2004	WestPlains	Rocky Ford	10	64.7	0.1	64.8		FERC Form 1
2004	WestPlains	WestPlains 1st add	45	29	0	29		FERC Form 1
2004	WestPlains	WestPlains 2nd add	5	29	0	29		FERC Form 1
2004	WestPlains	WestPlains 3rd add	10	29	0	29		FERC Form 1
2004	WestPlains	WestPlains 4th add	5	29	0	29		FERC Form 1

Year	Company	Plant	Cap (MW)	Cost ($/MWh) Fuel	O&M	Total	Shared	Data Source
2004	WestPlains	WestPlains 5th add	195	29	0	29		FERC Form 1
2005	ARPA	Lamar 3,4	3	50	0.2	50.2		Estimate
2005	ARPA	Lamar 6	25	20.4	1.2	21.6		Estimate
2005	ARPA	Trinidad 4	3	15	1.6	16.6		Estimate
2005	Basin Electric	Laramie River	702	5.4	1	6.4	Note 1	RDI
2005	Black Hills	Ben French GT	68	28.9	0.1	29		RDI
2005	Black Hills	Ben French IC	10	50	0.2	50.2		RDI
2005	Black Hills	Ben French ST	22	15	1.6	16.6		RDI
2005	Black Hills	Neil Simpson 1, 2	98	8.5	0.5	9		RDI
2005	Black Hills	Osage	30	14.3	0.1	14.4		RDI
2005	CO Springs	Drake	267	19.6	0.9	20.5		EIA-412
2005	CO Springs	George Birdsall	57	50	0.3	50.3		EIA-412
2005	CO Springs	Manitou	2	0	0	0		EIA-412
2005	CO Springs	Nixon	207	10.4	0.9	11.3		EIA-412
2005	CO Springs	Nixon CT 2	68	50	0	50		EIA-412
2005	CO Springs	Nixon CT1	68	50	0	50		EIA-412
2005	CO Springs	Ruxton	0	0	0	0		EIA-412
2005	CO Springs	Tesla 1	25	0	0	0		EIA-412
2005	IPPs	American Atlas	81	50	0	50		Estimate
2005	IPPs	Biogas 1 - IPP	4	10	0	10		Estimate
2005	IPPs	E Co IPP Hydro	14	0	0.1	0.1		Estimate
2005	IPPs	Greely Energy 1	68	50	0	50		Estimate
2005	IPPs	Ignacio Gas - IPP	6	50	0	50		Estimate
2005	IPPs	Wattenburg Field	1	50	0	50		Estimate
2005	MEAN	Ruedi	4	0	0	0		RDI
2005	PRPA	Rawhide	262	8.1	1.3	9.4		RDI
2005	PSCo	75th St Waste Water	1	12.9	0	12.9		PUC Staff
2005	PSCo	Alamosa	36	50	0	50		FERC Form 1
2005	PSCo	American Atlas	81	12.8	0	12.8		PUC Staff
2005	PSCo	Arapahoe	246	14	0.6	14.6		FERC Form 1
2005	PSCo	Boulder	20	0.2	0	0.2		RDI
2005	PSCo	Cabin Creek	215		0.7	0.7		RDI
2005	PSCo	Cameo	73	9	0.7	9.7		FERC Form 1
2005	PSCo	Cherokee	723	11	0.5	11.5		FERC Form 1
2005	PSCo	CO Power Proj 1	50	12.8	0	12.8		PUC Staff
2005	PSCo	CO Power Proj 2	68	12.8	0	12.9		PUC Staff
2005	PSCo	Comanche	660	10.1	0.4	10.5		FERC Form 1
2005	PSCo	Coors Biotech	3	12.8	0	12.8		PUC Staff
2005	PSCo	County Line Landfillill	1	12.8	0	12.8		PUC Staff
2005	PSCo	Craig	1264	10	0.7	10.7	Note 2	FERC Form 1
2005	PSCo	Fort Lupton	92	38	0	38		FERC Form 1
2005	PSCo	Fruita	17	50	0.1	50.1		FERC Form 1

Year	Company	Plant	Cap (MW)	Cost ($/MWh) Fuel	O&M	Total	Shared	Data Source
2005	PSCo	Ft. Lupton Cogen	150	12.9	0	12.8		PUC Staff
2005	PSCo	Ft. St. Vrain	475	29	0	29		FERC Form 1
2005	PSCo	Generic CT	104	29	0	29		Estimate
2005	PSCo	Generic CT	104	29	0	29		Estimate
2005	PSCo	Generic CT	181	29	0	29		Estimate
2005	PSCo	Generic CT	104	29	0	29		Estimate
2005	PSCo	Generic CT	181	29	0	29		Estimate
2005	PSCo	Generic CT	104	29	0	29		Estimate
2005	PSCo	Hayden	446	12	0.5	12.5		FERC Form 1
2005	PSCo	Hillcrest 1	2	0	12.8	12.8		PUC Staff
2005	PSCo	Monfort	32	12.8	0	12.8		PUC Staff
2005	PSCo	Mount Elbert PS	200		0.1	0.1		RDI
2005	PSCo	Pawnee	511	9	0.5	9.5		FERC Form 1
2005	PSCo	PSCO W CO Small Hydro	25	0	1.1	1.1		Estimate
2005	PSCo	Shoshone	14	0.3	0	0.3		FERC Form 1
2005	PSCo	Tacoma	9	0	0	0		FERC Form 1
2005	PSCo	Total Cogeneration	19	12.9	0	12.9		PUC Staff
2005	PSCo	U of CO Cogen	10	12.8	0	12.8		PUC Staff
2005	PSCo	Valmont GT	53	37	0	37		FERC Form 1
2005	PSCo	Valmont ST	189	13	0.5	13.5		FERC Form 1
2005	PSCo	West Power 1	122	12.8	0	12.8		PUC Staff
2005	PSCo	Windsource	4	20	0	20		Estimate
2005	PSCo	Zuni	107	47.4	0.3	47.7		FERC Form 1
2005	Tri-State	Burlington	100	50	0.2	50.2		RDI
2005	Tri-State	Delta 1	1	50	0	50		Estimate
2005	Tri-State	Delta 5	1	50	0	50		Estimate
2005	Tri-State	Delta 7	2	50	0	50		Estimate
2005	Tri-State	Laramie River	398	5.4	1	6.4		Ann Report
2005	Tri-State	Nucla	100	9.5	24.6	34.1		Ann Report
2005	WAPA	WAPA LAP E CO	198	0	10.9	10.9		RDI
2005	WAPA	WAPA LAP W CO	26	0	10.9	10.9		RDI
2005	WAPA	WAPA LAP WY	394	0	10.9	10.9		RDI
2005	WAPA	WAPA Salt Lake	310	0	8.9	8.9		RDI
2005	WestPlains	Clark	43	15.7	2.7	18.4		FERC Form 1
2005	WestPlains	Pueblo IC	10	38.8	0	38.8		FERC Form 1
2005	WestPlains	Pueblo ST	19	60.5	1	61.5		FERC Form 1
2005	WestPlains	Rocky Ford	10	64.7	0.1	64.8		FERC Form 1
2005	WestPlains	WestPlains 1st add	45	29	0	29		FERC Form 1
2005	WestPlains	WestPlains 2nd add	5	29	0	29		FERC Form 1
2005	WestPlains	WestPlains 3rd add	10	29	0	29		FERC Form 1
2005	WestPlains	WestPlains 4th add	5	29	0	29		FERC Form 1
2005	WestPlains	WestPlains 5th add	195	29	0	29		FERC Form 1

APPENDIX B

Rocky Mountain Power Area Generation Contracts

Purchaser	Seller	Expire	MW	Demand $/kW-Month	Energy $/MWh
ARPA	WAPA		30		
CSU	WAPA		63		
CSU	WAPA		59		
Delta-Montrose	Tri-State		90		
Empire Electric	Tri-State		70		
Estes Park	PRPA		16		
Fountain Electric	CO Springs		27		
Ft. Collins	PRPA		171		
Ft. Morgan	WAPA		288		
Grand Valley	PSCo		17	13.05	20.86
Gunnison	Tri-State		26		
Highline	Tri-State		156		
Holy Cross	PSCo		118	10.29	20.43
Intermountain	PSCo		140	12.98	20.25
Intermountain	WAPA		22		
K C Electric	Tri-State		52		
La Plata	Tri-State		126		
Longmont	PRPA		90		
Loveland	PRPA		72		
MEAN	WAPA		48		
Morgan County	Tri-State		56		
Mountain Parks	Tri-State		50		
Mountain View	Tri-State		74		
Pacificorp	Tri-State	2020	50	11.86	25.71
Poudre Valley	Tri-State		105		
PRPA	WAPA		167		
PSCo	American Atlas	2002	84	18.23	12.85
PSCo	Basin Electric Power	2016	150	12.99	10.84
PSCo	Betasso	2017	2.7	17.84	12.85
PSCo	Bridal Veil hydro	2012	0.5	18.02	12.85
PSCo	Brush Cogen	2019	68	10.54	12.85
PSCo	City of Boulder	2017	0.52	19.38	12.85
PSCo	City of Littleton	1998	0.23	18.00	12.85
PSCo	CO Power Partner	2008	50	10.51	12.85
PSCo	Coors Bio-tech	2022	2.8		12.85
PSCo	Dillon hydro	2002	1.66	10.41	12.85
PSCo	Foothills hydro	2000	1.94	20.11	12.85
PSCo	Lakewood hydro	2017	2.5		12.85
PSCo	Maxwell hydro	2015	0.07	20.11	12.85
PSCo	Denver Sewage	2000	5.5	20.11	12.85

Purchaser	Seller	Expire	MW	Demand $/kW-Month	Energy $/MWh
PSCo	Monfort	2011	32	10.33	12.85
PSCo	Mt. Elbert hydro	2000	2.8	13.35	12.85
PSCo	Orodell hydro	2017	0.22	17.84	12.85
PSCo	Ouray hydro	2014	0.5	18.02	12.85
PSCo	Pacificorp	2022	176	0	11.94
PSCo	PRPA	2004	226	15.37	17.63
PSCo	Roberts tunnel	2002	5	17.84	12.85
PSCo	Silver Lake hydro	2017	2		12.85
PSCo	Stagecoach hydro	2019	0.8	10.66	12.85
PSCo	Strontia Springs hydro	2001	1.15	11.30	12.85
PSCo	Thermo Carbonics	2009	122	10.34	12.85
PSCo	Thermo Industries	2019	150	10.33	12.85
PSCo	Tri-State 1	2001	100	13.23	14.99
PSCo	Tri-State 2	2017	100	13.23	14.99
PSCo	Tri-State 3	2016	50	13.23	14.99
PSCo	Tri-State 4a	2002	50	13.23	14.99
PSCo	Tri-State 4b	2001	50	13.23	14.99
PSCo	Tri-State 4c	1998	50	13.23	14.99
PSCo	Tri-State 4d	1999	50	13.23	14.99
PSCo	Tri-State 5	2011	100	13.23	14.99
PSCo	U of Co	2007	10	10.51	12.85
PSCo	U of N Co	2003	73	31.22	12.85
PSCo	Vallecito hydro	2004	5		
PSCo	Waste Management	2006	0.55	11.30	12.85
San Isabel	Tri-State		58		
San Luis Valley	Tri-State		64		
San Miguel	Tri-State		41		
Sangre De Cristo	Tri-State		14		
SE CO Power	Tri-State		33		
Tri-State	WAPA		368		
Tri-State	WAPA		292		
United Power	Tri-State		109		
WestPlains	PSCo		168		
White River	Tri-State		23		
Yampa Valley	PSCo		60	13.06	19.96
Y-W Electric	Tri-State		132		